

COMMITTEE HEARING
BEFORE THE
CALIFORNIA ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

In the Matter of:)
)
Preparation of the 2005 Integrated) Docket No.
Energy Policy Report) 04-IEP-01C
)
Re: Staff's Preliminary Natural)
Gas Assessment and Policy)
Issues)
_____)

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

THURSDAY, JULY 14, 2005

9:10 A.M.

Reported by:
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COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

ADVISORS PRESENT

Melissa Jones

Michael Smith

Scott Tomashefsky

STAFF and CONTRACTORS PRESENT

David Maul

Jairam Gopal

Lynn Marshall

Mark DiGiovanna

Mike Purcell

Jim Fore

Bill Wood

Leon Brathwaite

Angela Tanghetti

ALSO PRESENT

Richard Hendrix
Pacific Gas and Electric Company

Herb Emmrich
Semptra Energy Utilities

Joseph Sparano
Western States Petroleum Association

ALSO PRESENT

Mark Meldgin
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Robert T. Howard
Pacific Gas and Electric Company

Jeff Hartman
Semptra Utilities

Todd Peterson
Sacramento Municipal Utility District

Wendy Maria Phelps
California Public Utilities Commission

Sean Robledo Edgar
California Refuse Removal Council

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P R O C E E D I N G S

9:10 a.m.

PRESIDING MEMBER GEESMAN: Why don't we come to order. Sorry for the delay. This is our 46th day of workshops for the California Energy Commission Integrated Energy Policy Report. I'm John Geesman, the Presiding Member of the Integrated Energy Policy Report Committee. To my left, Commissioner Jim Boyd, the Associate Member of the IEPR Committee and the Presiding Member of the Commission's Natural Gas Committee.

To his left, Mike Smith, his Staff Adviser. And to Mike's left, Scott Tomashefsky, the Chairman's Staff Adviser.

I think the only thing I wanted to say in opening is everybody in the room realizes this is the most important driving factor in our various energy forecasts. So, we look forward to a good day, and hopefully we can address some of the uncertainties that inherently beset this field.

Commissioner Boyd.

COMMISSIONER BOYD: Thank you. The only thing that comes to my mind, pardon the pun, on this first Flex-Your-Power-Now day we've had in

1 the state, is I'm looking forward to today's
2 discussion in hopes of shedding some light on the
3 subject of demand, supply and thus, price, which
4 is driven by the two former, the two preceding
5 issues.

6 We've all had trouble with this issue of
7 price ever since we established a glass ceiling in
8 the 2003 -- glad it was a glass ceiling, because
9 we've reached it -- in the 2003 IEPR. So, as
10 Commissioner Geesman said, this gas is a
11 significant forcing function in the energy area.

12 So hopefully you all will set us
13 straight and have better ideas of where we need to
14 go and what we need to say in terms of policy
15 issues. So, thank you, and look forward to the
16 day.

17 PRESIDING MEMBER GEESMAN: Dave.

18 MR. MAUL: Good morning, Commissioners.
19 I'm David Maul, Manager of the Natural Gas and
20 Special Projects Office here at the Commission.
21 And we're very pleased that you're sponsoring this
22 IEPR workshop. We have observed your grueling
23 pace, but we hope that you'll find this to be the
24 most important of all the IEPR workshop hearings
25 that you are participating in.

1 We are really enthusiastic about this
2 event, the topic and the folks that have shown up
3 here today and will be making comments today.

4 Let me just quickly go over some
5 logistical items very quickly. For folks that are
6 listening to us right now there is a call-in
7 number that you have been able to call in and
8 you're able to listen to it. The etiquette for
9 calling in, please, for folks that are on the
10 line, if you would please mute your phone so any
11 unnecessary noise is not transmitted to the entire
12 world and all of us. So please put your phone on
13 mute, and maybe even your cellphone on mute, as
14 well. For the folks inside the room here, if
15 you'd put your cellphone on mute, as well.

16 We are also webcasting this entire
17 event. If you are having difficulty getting the
18 webcast, let me give you the web address for this.
19 It is on our Commission's website. And you can
20 not only hear the audio, but you can also see the
21 PowerPoint presentations as they are being given.
22 You'll see the same slides on your computer as we
23 see here in this room. And the web address is
24 www.energy.ca.gov -- that's our home page --
25 \2005 energypolicy\documents\2005-07-

1 04 hearing\presentations. And hopefully you can
2 write faster than I can talk.

3 So for today we have an agenda, we have
4 a couple parties who have already filed some
5 presentations, and so we've included those folks.
6 We have filings from PG&E and from the Semptra
7 Utilities, that's SoCalGas and San Diego Gas and
8 Electric. We have included those on the agenda
9 because we received those filings submittals
10 beforehand, their PowerPoint presentations.

11 Obviously, anybody else in the room is
12 very welcome to make public comment and
13 presentations. We view this as more of a
14 workshop, so we're actually encouraging parties to
15 have a discussion on some of the issues that we're
16 raising here today.

17 We have issued our report on the natural
18 gas assessment and titled it the preliminary
19 reference case. We are seeking some guidance from
20 both the Commission, as well as other parties
21 involved in this, on how we can resolve some of
22 the issues that we're dealing with in the modeling
23 area.

24 And because of that we have the demand
25 issues separated out because some of the parties

1 presentations are focused just on the demand side.
2 So, what we'd like to do this morning is once I
3 turn it over to Jairam Gopal, our supervisor for
4 the natural gas unit, we will be -- he will
5 provide an overview of our work.

6 We actually have a range of forecasts to
7 present to you today. At the late June IEPR
8 hearing on natural gas and electricity demand, the
9 report that was put out did include a natural gas
10 demand at that time, but that discussion was
11 deferred until today. So, Lynn Marshall of our
12 demand analysis office, who authored that report,
13 is here with us to join us today to discuss that
14 forecast.

15 And we also have the preliminary natural
16 gas reference case forecast, as well. And we view
17 these as a range of forecasts, and we're seeking
18 guidance from all the parties to improve both of
19 the forecasts.

20 Following the two presentations and
21 discussions of the results, as well as the key
22 drivers for the forecasts, we will have
23 presentations and comments by some of the parties
24 just on the demand portion.

25 Once we complete that then we'll get

1 back into the rest of the preliminary natural gas
2 assessment dealing with supply, infrastructure and
3 price issues. Follow that with comments from the
4 various parties, those that have submitted
5 comments, as well as those who would like to
6 either phone in comments or just stand at the
7 podium and provide discussion here.

8 We are quite happy to answer questions
9 from the Committee, as well as any of the parties,
10 as well, as we go along; have a discussion on
11 these issues.

12 Following that we're going to have a
13 discussion of policy issues which I think will
14 probably take place in the afternoon following the
15 lunch break. And, again, we have presentations
16 from PG&E and Sempra Utilities they have already
17 submitted to us. And so they have been included
18 on the materials we have.

19 With that, the last logistical note I
20 need to provide you, highlight, is that we have a
21 scheduled fire alarm drill sometime during the
22 month of July. And it's a lottery system of what
23 day it actually occurs. So for those folks who
24 are in the room who have not heard this
25 announcement yet, if you hear a pulsating fire

1 alarm then we all need to, very quickly, and --

2 PRESIDING MEMBER GEESMAN: Then we
3 either won the lottery or we lost the lottery.

4 MR. MAUL: Depending upon your
5 perspective and endurance.

6 COMMISSIONER BOYD: You have to explain
7 they have to differentiate between the alarm you
8 hear when those people go out the side door when
9 they shouldn't go out the side door, which goes on
10 at least once a hearing.

11 MR. MAUL: We have been informed that
12 the fire alarm drill is a pulsating alarm that you
13 will hear; and the solid alarm that you hear from
14 the door is to be ignored, if you can.

15 Anyway, if there is a fire alarm drill,
16 folks who are in the audience please exit the door
17 right here. Do not go out the emergency door. Go
18 out to the right; go out the main doors; keep
19 going to your right. Go to the corner and please
20 observe the red lights. There will be CHP
21 ticketing jaywalkers, as we have been well
22 informed here at staff. So we would hate to have
23 any of our guests receive a ticket from the CHP
24 for jaywalking.

25 COMMISSIONER BOYD: New York this isn't.

1 MR. MAUL: Hopefully we'll get through
2 today with no fire alarms.

3 With that, let me turn it over to Jairam
4 Gopal, our supervisor of the natural gas unit.
5 Jairam, go ahead.

6 MR. GOPAL: Thank you, Dave. Good
7 morning, Commissioners and the interested parties.
8 You folks are true believers of energy if you have
9 attended all these 46 workshops, along with the
10 Commissioners. Kudos to the Commissioners for
11 sitting through all this.

12 And, today, of course, as Dave
13 mentioned, we're going to be talking about natural
14 gas market assessment. There are a couple of
15 things that I want to bring out regarding the
16 files, the hard copy that you folks have.

17 The first page looks the same in two of
18 the packages, so if you'll turn over to the second
19 page if you see natural gas demand projections you
20 have the right package open right now. The other
21 one which says model analysis, that's for the
22 second half of the morning session.

23 The process is as Dave mentioned, we
24 will talk about demand projections in the
25 beginning. Complete the demand discussions with

1 the staff presentation and the parties who will be
2 talking about demand.

3 Then we will switch over to model
4 analysis, model methodology, supply analysis, the
5 infrastructure issues, and finally the price
6 implications.

7 And then we will have a question-and-
8 answer session to address any questions, inquiries
9 that people have.

10 Basically we'll talk about gas demand
11 projections right now. This slide I don't really
12 need to address too much because Dave has covered
13 most of the issues here. We have had quite a few
14 workshops that have led to this workshop today.

15 We will be discussing the preliminary
16 reference case. As a result of this workshop any
17 comments received by you folks and recommendations
18 from the Committee will form the basis for the
19 final reference case that will support the 2005
20 IEPR.

21 Policy issues will be discussed in the
22 afternoon. And a variety of staff, Lynn Marshall
23 and Mark DiGiovanna will be talking about the
24 demand issues in the first half of this morning.
25 And then we'll have Leon Brathwaite, Mike Purcell,

1 Bill and Mark talking about other issues. I will
2 introduce them again as we go along.

3 Basically demand projections, we do have
4 one from the demand analysis office, which we have
5 continued to, you know, analyze. We'll talk about
6 the methods by which the demand analysis has been
7 historically conducting the natural gas demand
8 analysis.

9 Since the last, the 2003 IEPR, one of
10 the major comments received was in analyzing the
11 gas market we should probably pay more attention
12 to price elasticity and impact of natural gas to
13 not only it's own prices, but also the other
14 factors that drive the natural gas market.

15 As a result we have incorporated
16 elasticity analysis in the model. That also gives
17 us a gas demand projection. So we have this range
18 of gas forecasts that we will be considering in
19 today's discussion and in the following few weeks.

20 So with this let me first bring on Lynn
21 Marshall from the California Energy Commission.

22 MS. MARSHALL: The forecasts I'm
23 discussing were prepared by the demand analysis
24 office; and they're documented in a couple of
25 reports that we have copies of out in the lobby.

1 Our staff energy demand forecast report presents
2 both the electricity and natural gas forecasts and
3 the methods report has great detail on the
4 methodologies and assumptions used.

5 The electricity demand forecast, which
6 was, as Dave mentioned, was discussed at the June
7 30th workshop, was used to develop the UEG
8 projections used in the natural gas outlook we're
9 discussing today.

10 What I'm presenting now is the natural
11 gas end user forecast that are the product of the
12 same model and assumptions. Those forecasts are
13 for -- cover the entire state, both core and
14 noncore. We forecast by planning area, but we do
15 include in there the publicly owned utilities, but
16 there's no cogeneration or UEGs. This is strictly
17 end user natural gas consumption.

18 Generally, our methodology, we're using
19 our sector end use models for the residential,
20 commercial and industrial model sectors. Our
21 residential and commercial end use models have
22 been developed inhouse over the years. And for
23 the industrial sector we used INFORM, which is a
24 similar end use type model that was developed by
25 EPRI. And we have an econometric model for the ag

1 and water pumping sector.

2 These models generally are forecasting
3 electricity and natural gas jointly. In the
4 electricity hearing -- in the hearing on the
5 electricity demand forecast, we discussed a number
6 of variables that present the most uncertainty for
7 our forecast. And as a result of that we're now
8 in the process of developing a range of forecasts.
9 So the forecasts that I'm presenting today, the
10 gas forecast will be adjusted somewhat as a result
11 of that process.

12 I'll point out some of the variables
13 that are in question that we're looking at and
14 modifying for those scenarios. So people might,
15 as we discuss the different natural gas demand
16 forecast outlooks today, keep in mind whether
17 there are other uncertainties that we need to
18 address on the natural gas side; or whether the
19 approach we're taking to develop a range of
20 forecasts for the electricity side will work as
21 well for natural gas.

22 Key drivers for each sector. In the
23 residential sector we use the Department of
24 Finance population forecast. And from that, using
25 our own projections of persons per household we

1 develop a household projection forecast for each
2 planning area in the state.

3 We also have now included the effects of
4 building and appliance standards all the way
5 through the 2005 building standards. And we are -
6 - the natural gas price projections we are using
7 are based on an earlier NARG run because of the
8 iteration process. We're using an old NARG price
9 projection. The next time we run our models we'll
10 try and get the new NARG outputs. We have to kind
11 of iterate back and forth that way.

12 In the commercial sector we are
13 projecting -- main driver is commercial floor
14 space, and we are assuming that floor space
15 additions are going to grow at about the same rate
16 as we've seen since 1990. We also use the same
17 natural gas price forecast; and again, we have the
18 effects of building and appliance standards.

19 Industrial sector, which we forecast at
20 a fairly detailed level, two to three digit --
21 groups, we're using the value added projections by
22 economy.com. And both natural gas and electricity
23 prices. So the industrial sector demand is
24 process energy in particular is affected by
25 electricity and natural gas prices jointly.

1 For the mining sector we use employment
2 as the driver.

3 Okay, and this is the natural gas price
4 forecast that we are using. And you'll note in
5 the early years it's -- we've got a bit of a
6 decline and we don't see a big increase in prices
7 until past 2010. So that's affecting our
8 forecast, particularly in the industrial sector's
9 most price sensitive.

10 Okay, so here's our new forecast
11 compared to the last published forecast.
12 California energy demand 2003 was our previous
13 forecast. CED 2006 is the new one.

14 So on the bottom you can see the PG&E
15 forecast. The big difference is just due to
16 differences in starting point. 2003 demand was
17 considerably lower than forecast previously. The
18 big decrease there is in the industrial sector.
19 About half of that, I think, is in refining.

20 The growth rate for PG&E is actually a
21 little higher and that's driven by a couple of
22 things. One, we have higher household
23 projections, particularly in the SMUD area. So we
24 have a slightly higher growth rate for the
25 residential sector. We also have a little higher

1 growth rate in the industrial sector, because the
2 starting point is now lower. So there's more a
3 rebound from the big decline in the industrial
4 sector on PG&E.

5 Now, in souther California, our San
6 Diego forecast is not that much different than the
7 previous one. So the big differences are with
8 respect to the SoCalGas area. Not much of a
9 starting point difference, but we have a much
10 lower growth rate. And primarily what's driving
11 that is change in our projections about the mining
12 sector, TEOR demand. At this time we're assuming
13 that consumption in the sector is going to be
14 decreasing at more than 1 percent a year. It's
15 following, I think, most people's projections that
16 extraction in California is on the decline and
17 going to continue to decline, as it has since
18 about 1998.

19 PRESIDING MEMBER GEESMAN: Can you
20 elaborate on that, the basis for those
21 assumptions?

22 MS. MARSHALL: The conventional wisdom
23 is that extraction -- if you look at the historic
24 data, the extraction data in California, it has
25 been declining since mid to late '90s. And so the

1 oil and conservation, their view is that there's
2 less oil in the ground and so extraction is going
3 to continue to decline.

4 PRESIDING MEMBER GEESMAN: Then is there
5 any price correlation that might counter that
6 assumption?

7 MS. MARSHALL: Well, I'll go to the next
8 chart. I think that's an interesting question
9 because if we look -- this is the demand forecast
10 by economic sector, and in the middle there's kind
11 of a purple line, and that's the mining sector.
12 And you can see since it has been declining since
13 about 1997, but now we see, in the last two years,
14 and obviously gas prices are much higher, we see a
15 lot more activity in -- or petroleum prices are
16 higher, so there appear to be putting more energy
17 into extraction. So we've seen a much higher
18 level in the last two years.

19 Now, is that going to continue? I don't
20 know. So, I think this is probably the sector
21 with the greatest uncertainty as to how that's
22 going to evolve. Whether they're going to be
23 willing to invest more in technology. And so we
24 could see gas demand increase in that sector. Or
25 whether the conventional wisdom is right, and it's

1 a declining resource and so it's going to continue
2 to --

3 PRESIDING MEMBER GEESMAN: Do we --

4 MS. MARSHALL: -- go back to the earlier
5 trend and decline.

6 PRESIDING MEMBER GEESMAN: Do we track
7 well count, or drilling rig count? Or is there
8 any other variable there that might test the
9 assumption?

10 MS. MARSHALL: The Department of Oil and
11 Gas tracks that type of activity. And when you
12 look at the extraction numbers it looks like --
13 and they report that there are wells closing. So
14 it's hard to see from that, you know, what's going
15 to drive a turnaround.

16 But, on the other hand, looking at our
17 gas consumption data there seems to be something
18 happening. You know, is that a short-term or a
19 long-term effect, I don't know.

20 MR. MAUL: Yeah, Commissioner, could I
21 add on that one, we meet with our Division of Oil
22 and Gas in the state every month and talk about
23 those kinds of issues.

24 We do track the number of permits that
25 have been polled for new wells. We track the

1 number of wells that are drilled, the production
2 by sector in California, oil production and gas
3 production.

4 And there's two competing trends here.
5 One is if you're an economist you would believe
6 that there is enough oil and gas still left in the
7 ground that with higher prices we should see more
8 production and an increase as we have seen in the
9 last couple of years.

10 On the other hand, if we look at the
11 number of permits that are being pulled, the
12 permits are on average for the last couple of
13 years, and so we don't see a significant change in
14 the number of permits. And unfortunately, the
15 total production that's being recorded here
16 recently is still on the very slow decline.

17 Now, with higher prices the last two
18 years, there is a lag time between the companies
19 finally saying, okay, let's go make an investment
20 and pulling a project together. Getting the
21 permit; drilling the hole; and finally getting
22 production.

23 So, there's about an 18 month to two
24 year lag time in there. So, it's kind of a
25 turning point here, which way it might go in the

1 future. And it's just not entirely clear.

2 PRESIDING MEMBER GEESMAN: But based on
3 your interaction with the Division of Oil and Gas
4 you feel that your assessment is a quite current
5 one?

6 MR. MAUL: For Lynn's or Mark's
7 assessment? Because we have two different
8 perspectives on the future. From an economic
9 perspective I would say we would expect some
10 increase in production from the reality of
11 permits, maybe declining production.

12 And our data is, well, a few months old.

13 PRESIDING MEMBER GEESMAN: Okay. Thank
14 you.

15 MS. MARSHALL: I think Mark and I are
16 both using the same TEOR demand.

17 COMMISSIONER BOYD: It will be
18 interesting to see if the oil industry has any
19 comments or a different view.

20 PRESIDING MEMBER GEESMAN: Yeah.

21 MS. MARSHALL: I think we would love to
22 get more information. We don't have a lot of
23 expertise inhouse on that particular industry.

24 PRESIDING MEMBER GEESMAN: Sometimes
25 they're not long on information that they want to

1 share with us.

2 MR. SMITH: Hey, Lynn. Given the lag
3 time that Dave describes, have you or your staff
4 attempted to correlate your employment data, which
5 you indicate is a driver in your forecast, with
6 the permits and any other production data from oil
7 and gas, to see if there is a -- if they do track
8 over time?

9 MS. MARSHALL: No, --

10 MR. SMITH: Recognizing there is a lag
11 between decisions to invest and actually
12 investing.

13 MS. MARSHALL: Haven't done that.
14 Employment -- maybe I could skip ahead to this
15 chart since we're talking about TEOR. There we
16 go.

17 The relationship between consumption and
18 employee -- employment is somewhat erratic. We
19 don't really have a good driver for this sector.
20 But the employment projections that we're using,
21 they do correlate pretty well with EIA's
22 projections for extraction in onshore extraction
23 in the west, in the lower 48.

24 So we were using that as a proxy for
25 what is EIA's projection of extraction activity in

1 California. It's declining. And that actually
2 might be declining a little more than this
3 employment forecast.

4 So, you know, historically I don't think
5 we really have a good driver. This is the
6 assumption we're making about what the future of
7 the industry is.

8 Okay, I'll go back to -- talk about some
9 of the other economic sectors. Residential
10 forecast is growing a little less than 1 percent.
11 Industrial a little more than that, little more
12 than 1 percent. And I'll talk about each of these
13 specifically.

14 In the residential sector we have, this
15 shows use per household, as well as the household
16 projections we're using. Use per household is
17 declining at a somewhat slower rate than history.
18 And that's partly reflecting rising persons per
19 household. So our use per household is greater in
20 the forecast period, relatively greater. So we
21 don't have as much of a decline as if we were to
22 hold persons per household constant.

23 One of the variables we're going to be
24 looking at in developing the electricity demand
25 forecast range is varying our demographic

1 assumptions so that we'd actually have more
2 households. And so the residential demand, we'll
3 come up with a high end from that.

4 And the commercial sector we're looking
5 at use per square foot, and the floor space
6 projections that we've developed. In recent
7 history, in the last decade or so, we've seen
8 increasing use per square foot. However, because
9 of the effects of building and appliance standards
10 that are accounted for in our models, we have in
11 the forecast period declining use per square foot.

12 And, again, as we go forward developing
13 a range of forecasts, this is a parameter that
14 we're going to be varying, perhaps adjusting the
15 effects of building standards. So we'd be coming
16 up with a higher commercial floor space forecast
17 as an upper range compared to this.

18 PRESIDING MEMBER GEESMAN: And the
19 approach you took here was the same as in the
20 electricity forecast?

21 MS. MARSHALL: Well, --

22 PRESIDING MEMBER GEESMAN: In terms of
23 the level of compliance?

24 MS. MARSHALL: When we make those
25 changes, some things are separate. But as we go

1 forward developing this electricity forecast
2 range, a lot of those are going to affect natural
3 gas at the same time.

4 PRESIDING MEMBER GEESMAN: Right.

5 MS. MARSHALL: Some of them, you know,
6 the standards we could maybe model individually.
7 But I think one issue for parties is do we want to
8 take the same approach, or are there other
9 parameters we ought to be varying.

10 And then finally this is -- not --
11 almost finally -- industrial natural gas
12 intensity. So we have the consumption per dollar
13 value added declining over time. Probably not as
14 great a rate as we've seen declines in history.

15 The growth in the industrial natural gas
16 demand, about one-third of it is in the food and
17 beverage industry and food processing. Some of
18 that growth may reflect production of higher value
19 added products, more expensive products. So that
20 may not -- that may translate into a more rapidly
21 declining use per dollar than we show here. So
22 that's a parameter we're going to vary to develop
23 a low case. So that would be reducing our
24 industrial demand forecast a little bit below what
25 it is here.

1 And we already talked about the mining
2 industry in great detail, so I won't -- that is
3 all of my slides. Does anybody have any questions
4 specifically on this? Or should we go on to
5 Mark's?

6 PRESIDING MEMBER GEESMAN: Thanks, Lynn.

7 MS. MARSHALL: Okay.

8 MR. GOPAL: Thank you, Lynn. Now we
9 will take on the natural gas demand projections
10 with Mark DiGiovanna talking about how the elastic
11 demand has been represented in the NARG model that
12 we are using.

13 He will also talk about the natural gas
14 demand for power generation. That's conducted by
15 the electricity office here in the Commission. So
16 he'll be talking about the end use sectors plus
17 power generation.

18 Mark.

19 MR. DiGIOVANNA: Good morning. Just in
20 case you feel like you might not get enough demand
21 forecasts before the day's over, I'll go ahead and
22 throw a few more at you.

23 First thing that I'm going to do is take
24 you through the method that we're using, both
25 outside of the NARG model, which is our primary

1 assessment tool, and then also how what we do
2 outside the model actually works within the model.

3 Show you geographically what it is that
4 we're trying to forecast. Which end use sectors
5 we're trying to come up with a forecast for. And
6 then I want to take you to just a little bit about
7 how we're doing this.

8 So once we get through how we're
9 modeling each sector, I will actually go through
10 the results that we're getting from this process.

11 So, this map right here shows the demand
12 regions that we are using in the 2005 natural gas
13 market assessment. One thing that makes our
14 modeling work a little unique compared to other
15 work done at the Energy Commission is there's
16 really no way to know what sort of infrastructure
17 needs there are going to be; what's going to go on
18 with supply; what's going to go on with prices, if
19 you just try to isolate your analysis to
20 California, or even just the west.

21 The natural gas market really is a
22 continental market, so we have to basically come
23 up with a demand forecast and all the supply
24 information for the entire continent.

25 So, as you can see here for the pretty

1 much east of the Rockies we're going by U.S.
2 Census Bureau's census regions; aggregating a lot
3 more once we get out west. It's far more
4 disaggregated, so we can get a little more
5 specific results out in the west.

6 All right. Here's a list of the sectors
7 that we look at in our model. First of all, in
8 the U.S. and Canada we're looking at residential
9 demand, commercial demand. And then a variety of
10 different industrial demands.

11 All of the regions I should say in the
12 U.S. and Canada, we're looking at gas demand for
13 chemical manufacturing; and then the gas demand
14 for basically all the other industrial processes,
15 with the exception of the two that are listed
16 right below there.

17 For California we do look at the demand
18 for thermally enhanced oil recovery. And we
19 actually use the forecast that was provided by our
20 demand analysis office.

21 And then in Alberta we're also looking
22 at the natural gas demand for bitumen extraction
23 and upgrading. Of course, we're also looking at
24 power generation demand in all of these regions.
25 And for a few of the -- basically just for Alaska,

1 in terms of the United States, we just grouped
2 that together as total demand.

3 Alaska's really, I mean, until they
4 build the Alaska pipeline, they're really not
5 connected to the grid like other areas in the
6 country. So, we have that demand in there, but
7 it's really not going to affect the results. And,
8 in fact, I'm not going to get into any of those.

9 And then in Mexico, again we're not
10 looking at sectoral demand; we're just looking at
11 total demand in four different regions in Mexico.

12 All right, now as far as how we actually
13 model each of these sectors. As Jairam mentioned,
14 since the 2003 IEPR we have received quite a few
15 comments that our natural gas demand analysis
16 should consider the effect of natural gas prices.

17 As we moved forward working kind of
18 parallel to this on the Western Interstate Energy
19 Board western gas study we received similar
20 comments. So we went ahead and decided to move
21 forward with that. As it works out we're very
22 fortunate because the NPC had just finished their
23 modeling work for their 2003 study.

24 Part of that, even though it really
25 wasn't the part that was published in the report,

1 they actually used the NARG model, which is what
2 we used. And they had developed a method --
3 actually Dr. Ken Medlock at Rice University,
4 developed a method to consider the price
5 elasticity for a variety of different sectors.

6 So we were able to retain him, kind of
7 cater the methods that he used to the way that we
8 do things. And that's how we've approached it
9 here.

10 Now, as far as the actual sectors that
11 we're modeling as, you know, considering the price
12 elasticity within the model, those are the
13 residential, commercial and the industrial sectors
14 with the exception, of course, of bitumen
15 extraction and treating and the thermally enhanced
16 oil recovery. Just because we don't have a
17 methodology to do that.

18 The inelastic demand nodes -- and when I
19 get to the power generation I can explain this
20 further, but basically in the inelastic demand
21 nodes what we've done is we're taking a forecast
22 done by someone else and using it in our model.
23 It doesn't interact with our model. Whatever
24 demand we put into our model will meet that.

25 So those are power generation. Again,

1 the oil sands extraction upgrading; thermally
2 enhanced oil recovery. And then anywhere we've
3 aggregated demand into total demand, that's in
4 there as an inelastic demand node.

5 So, how we're doing. For residential
6 and commercial natural gas demand those are both
7 functions of income, as measured by GDP;
8 population; heating degree days; and then, of
9 course, the price of natural gas.

10 For the -- now, for both of these two
11 sectors they actually have different elasticities.
12 They'll react differently to these variables, but
13 they just happen to use the same variables.

14 For income, like I said, for the U.S.
15 we're using GDP. To stay consistent with the
16 power generation forecast that we use for the
17 eastern half of the United States, which came from
18 EIA, we just went ahead and adopted their economic
19 growth assumptions.

20 They actually vary by year, but over the
21 forecast horizon they average out to about 3.08
22 percent growth per year.

23 Just to give you some idea of how
24 realistic that is, if you look at 1990 through
25 2004, GDP grew at about 3.06 percent per year on

1 average. So for population, two different sources
2 here.

3 For everything outside of California we
4 used the U.S. Census Bureau's most recent forecast
5 which just came out last April. That's based on
6 the 2000 census. For California we, like the
7 demand office, we used the Department of Finance's
8 population forecast. And that, I believe, came
9 out last May 2004.

10 For heating degree days we used the
11 average heating degree days from 1985 to 2000.
12 These variables are all region-specific. And then
13 the price of natural gas is actually generated
14 within the model and has sort of a dynamic
15 influence within the model.

16 As far as industrial natural gas demand
17 goes, like I say, we've broken this into two
18 different sectors that we're modeling with the
19 elasticity, chemical manufacturing and non-
20 chemical manufacturing. And the reason is that
21 the chemical manufacturing will actually react a
22 lot different, not just the change in natural gas
23 prices, which it is much more sensitive to. It is
24 also much more sensitive to all the other drivers
25 for industrial.

1 And the drivers for the industrial
2 sector, it's the same for both, the elasticities
3 are different for each, are industrial production,
4 the cross-price elasticity, which in this case
5 we're using an own price. In fact, it's the EIA's
6 high A own price. And then, again, the price of
7 natural gas, which is generated within the model.

8 On this slide here this is just showing
9 you the actual elasticities that are used in the
10 model. Now, most of these, the GDP, the cross-
11 price elasticity, industrial production,
12 population, this is all determined outside the
13 model.

14 Obviously, as the model is running we
15 don't, you know, need population to change or
16 weather to change, or we couldn't even if we
17 wanted it to. So, that's all determined offline.
18 And then once we put it in the model, the only
19 thing that actually goes into the model is the own
20 price elasticity.

21 And then this term right here at the
22 bottom, the $Q(T-1)$, is a lag parameter. And that
23 is basically put in there to allow us to go from
24 short-run elasticities to a long-run elasticity.
25 And to account for basically just the reaction

1 time it takes to change behavior.

2 And as you can see by looking at this,
3 particularly in the industrial sector, the
4 chemical sector shows the highest degree of, you
5 know, reaction to changes in price. But if you
6 also look through, especially compared to the
7 other industrial manufacturers, they also react a
8 lot more strongly to the other parameters. And
9 this will come into play as I go through the
10 results.

11 PRESIDING MEMBER GEESMAN: Mark, why do
12 you think your R-squares are so much higher on the
13 industrial and chemical sector?

14 MR. DiGIOVANNA: I don't know for sure
15 exactly; probably because weather is not a
16 variable would be my guess.

17 PRESIDING MEMBER GEESMAN: Thanks.

18 MR. DiGIOVANNA: All right, how we model
19 electricity generation. Kind of two things that
20 we do here. For the eastern half of the United
21 States, and for basically all of Canada, except
22 for Alberta and British Columbia, we're in a
23 position where we have to go out and find
24 forecasts. And just accept them and put them into
25 our model.

1 So for the United States east of the
2 Rockies, we have used EIA's annual energy outlook
3 2005 forecast for each of those census regions.
4 And that's the reference case forecast.

5 For Canada we actually used a forecast
6 derived by Navigant for, I think it was Imperial
7 Oil, in their proceedings regarding the MacKenzie
8 pipeline. Honestly, that was about one of the
9 only Canadian power gen forecasts that we could
10 find.

11 Out west it's a lot different. Out west
12 we generate these forecasts inhouse, our
13 electricity analysis office does. This is, as
14 Lynn explained, for California they incorporate
15 electricity demand forecasts generated by Lynn.
16 They use a variety of other electricity demand
17 forecasts for the other states and provinces in
18 the WECC.

19 And then they use the natural gas prices
20 that we provide them. And they're basically able
21 to go through, simulate what the dispatch would be
22 over the forecast horizon, give us a fuel burn,
23 which we then take and put back in our model. Run
24 our model again and see how that changes prices.
25 And then give those prices back to the electricity

1 office.

2 This process here is probably the most
3 active iterative process that we have. And the
4 reason is that we're trying to capture the effect
5 of the change in natural gas prices.

6 Now, one thing about the way the prices
7 are affecting the electricity model is an overall
8 increase in natural gas prices, which would
9 probably affect the other sectors, or would affect
10 the other sectors, doesn't have as much of an
11 impact on electricity generation as does relative
12 changes in prices in different regions.

13 Because when that happens it ends up
14 shifting generation into other regions, so that's
15 why we need to go through this iterative process
16 until things calm down.

17 Some reasons we don't do it
18 econometrically is that EIA switched their
19 methodology of how they collect and report
20 historical electricity generation, natural gas
21 consumption. So there really isn't enough
22 historical data to go back and try to come up with
23 an econometric model.

24 And because of all the changes over the
25 past five years, particularly the last four years

1 after the energy crisis, that if you were to try
2 to come up with some sort of an econometric
3 function it might get kind of squirrely on you.

4 And so the electricity office has an entire
5 model that can do this, so that's how we handle
6 it.

7 MS. JONES: Mark, --

8 MR. DiGIOVANNA: Yes.

9 MS. JONES: -- can you explain a little
10 further why it is that the natural gas prices
11 don't affect demand much in the electricity
12 sector?

13 MR. DiGIOVANNA: Well, the reason is
14 that the nongas-fired resources that are out
15 there, your nuclear, your coal, wind, tend to be
16 dispatched first. So, your load followers and
17 your peaking facilities are going to tend to be
18 your gas facilities.

19 So if there's a change in the overall
20 level of natural gas prices there really isn't
21 another resource to go to. You've already
22 dispatched all your coal and nuclear and you're
23 using whatever wind or renewables are available.

24 So at that point there's not another
25 resource to go to. Now, if you have changes in

1 two different regions you do have a choice
2 between, you know, is it more efficient to
3 generate in another area and deal with the line
4 losses, or you know, one area to the other. So
5 that's why we see not a big effect from an overall
6 change, but a lot of an effect from regional
7 changes.

8 PRESIDING MEMBER GEESMAN: Do you assume
9 any fuel switching from gas to oil in any of the
10 regions for electricity generation?

11 MR. DiGIOVANNA: We don't. And, as far
12 as I know, the electricity model actually doesn't
13 consider that.

14 PRESIDING MEMBER GEESMAN: I don't think
15 it's available in very many regions --

16 MR. DiGIOVANNA: Yeah, I was going to
17 say, in the western U.S. it's actually really
18 there aren't very many facilities that could even
19 do that. So I don't know how much of a
20 consideration.

21 And quite frankly, given the price of
22 oil, the odds of them switching over, I think on a
23 Btu basis, oil is still more expensive, so.

24 MR. MAUL: Commissioner, we do consider
25 a little bit of fuel switching in the industrial

1 and home-heating side on the east coast, but we
2 don't see much of it at all here in the west. In
3 fact, I don't think we have any states that have
4 power gen fuel switching going on.

5 MR. DiGIOVANNA: All right, go through
6 the results here. First of all, I want to point
7 out to those of you who have seen this chart in
8 the report, please disregard what you saw in
9 western Canada. There was a little snafu with the
10 spreadsheet there. This map here is a little more
11 accurate.

12 Just to let you know the way we see
13 things, at least in our model, in terms of natural
14 gas projections for the lower 48 states as a
15 whole, gas demand in just the lower 48 we see
16 growing from 2006 to 2016, growing from 58 bcf per
17 day to 70 bcf per day.

18 That represents about a 1.7 percent
19 annual growth rate. Most of that, about almost
20 three-quarters of that, is because of power
21 generation. And beyond that, most of that growth
22 from power generation is actually outside of the
23 west, which is a little bit different than what
24 we've had and what we've seen in previous
25 forecasts.

1 In fact, the overall lower 48 growth in
2 natural gas demand from power generation is about
3 4.3 percent per year. And if you just look at the
4 WECC the growth rate is actually only about 1.3
5 percent per year. So you can see there's a lot of
6 growth in gas demand from power generation in the
7 eastern U.S.

8 And part of the reason is they have room
9 for it. They have historically had a lot more
10 nongas-fired resources than we have out west,
11 particularly in California. So, there's a lot
12 more room for growth in building new gas-fired
13 generation.

14 Now, just looking at the other sectors,
15 residential demand for the lower 48 states, growth
16 is about an eighth of a percent a year; commercial
17 demand we show growing about 1.8 percent per year.

18 And for industrial demand, U.S.-wide,
19 it's essentially flat. It actually goes from 19.6
20 bcf to 19.4, but it's essentially flat. And the
21 reason for that is, which we'll kind of get more
22 into in the later presentations, is because of
23 rising natural gas prices.

24 And then just for Canada, pretty much
25 Canada-wide growth for total gas demand will grow

1 at about 1.3 percent per year, going from about
2 8.9 bcf per day to 10.1 bcf per day by 2016.

3 All right. This slide here is showing
4 the projected residential gas demand that we came
5 up with in our model. And as I'm sure you'll
6 notice, it is different than what the natural gas,
7 or I'm sorry, the demand analysis office came up
8 in their analysis. And basically I mean one of
9 the main things is we're just showing a little bit
10 stronger growth in basically in all of the service
11 territories.

12 But PG&E is, in ours, showing the
13 strongest growth, about 1.6 percent per year;
14 growing from 558 million cubic feet per day in
15 2006 to 655 million cubic feet per day in 2016.

16 SoCal we're showing growing about 1.3
17 percent per year; in San Diego growing about 1.4
18 percent per year.

19 Now, in the method that we're using, the
20 primary driver is going to be population growth.
21 And in the case of the Department of Finance
22 population forecast the reason we're seeing the
23 strongest growth in PG&E is that they have the
24 most, they have the strongest population growth
25 over the next ten years, around 1.4, 1.5 percent

1 per year.

2 In SoCal and SDG&E for about the first
3 half of the forecast it's a pretty similar growth
4 rate; and then dropping off to either 1 percent
5 per year or less than that for the second half.
6 So that's why they don't grow quite as much.

7 PRESIDING MEMBER GEESMAN: And household
8 size doesn't factor into your model, does it?

9 MR. DiGIOVANNA: Not explicitly.

10 PRESIDING MEMBER GEESMAN: Okay. So you
11 focus on population, as opposed to size of the
12 household, or perhaps evolving changes in size of
13 household?

14 MR. DiGIOVANNA: Right. The work that
15 was done by Ken on this is, you know, he regressed
16 the gas consumption just to changes in population.

17 PRESIDING MEMBER GEESMAN: Okay. Does
18 income --

19 MR. DiGIOVANNA: Income is also another
20 variable here that is contributing to the positive
21 growth in the population forecast -- I mean,
22 sorry, in the residential gas demand forecast. It
23 plays kind of secondary role to population in the
24 residential forecast. And then when you get into
25 the commercial forecast, they kind of trade

1 places. Income plays a greater role in explaining
2 the growth in commercial gas demand, and
3 population plays a secondary role there.

4 PRESIDING MEMBER GEESMAN: But would
5 differences in growth and income help to explain
6 the differences between SoCalGas and PG&E in this
7 slide?

8 MR. DiGIOVANNA: Not in this slide. And
9 actually the income that we use as a driver in our
10 model is actually national GDP.

11 PRESIDING MEMBER GEESMAN: So it's not
12 personal income.

13 MR. DiGIOVANNA: It's not personal
14 income or per capita income. And the reason is,
15 and it's the same income used throughout the U.S.
16 And the reason is that in developing this
17 methodology, when Ken went through trying to come
18 up, use regional income as a variable, actually
19 didn't have as good of an explanatory power as
20 just using GDP. So in this case we just have the
21 one income in there.

22 PRESIDING MEMBER GEESMAN: So it's your
23 belief then in your model that the primary
24 explanation for the difference in growth rates
25 across the three California utilities would be

1 population growth differences?

2 MR. DiGIOVANNA: Yes. Because when we
3 get into later on this afternoon into the price
4 forecast, you'll see that the prices are moving in
5 a similar manner in all three utility areas. So
6 the primary difference between all of these is the
7 population growth.

8 In that one, when we used the Department
9 of Finance population forecast, we used the
10 forecast by county so we're, you know, able to
11 split out the counties by service territory. So
12 you do end up with different growth rates for the
13 different utilities.

14 PRESIDING MEMBER GEESMAN: Okay.

15 MR. DiGIOVANNA: All right, this next
16 slide, just to give you some perspective here
17 where California's residential gas demand is.
18 This compares it to the demand for all of the
19 other western states, excluding California, and
20 for western Canada.

21 And as you can see, on an absolute
22 basis, California's residential gas demand is
23 basically higher than anybody around us, even
24 combined. And in terms of the western states and
25 California, they're both growing at about the same

1 rate. Statewide we're growing at about 1.4
2 percent; the western states are growing at about
3 1.4 percent.

4 Western Canada, which has its own
5 population and income assumptions embedded in that
6 part of it, is showing much less growth. About
7 half the rate of growth, .7 percent per year.

8 And now, Commissioner Geesman, that one,
9 too, you probably are seeing an effect of a
10 difference in income because the Canadian GDP is
11 assumed to grow at about 2.49 percent per year on
12 average.

13 PRESIDING MEMBER GEESMAN: Um-hum.

14 MR. DiGIOVANNA: So, that will play into
15 that.

16 All right, this is the projection for
17 commercial gas demand. Now, in all of the regions
18 that we're looking at we're seeing pretty strong
19 growth in commercial gas demand. And a lot of,
20 like we've seen earlier, has to do with the income
21 assumption that we're using.

22 Even though over the past 14 years we've
23 had a pretty similar average annual growth rate
24 than what we're using, the difference is over the
25 past 14 years it wasn't very constant. I mean

1 there was actually two recessions. So, the
2 average growth rate that we're seeing here is a
3 little bit high compared to historical standards.

4 The highest growth rate again is in
5 PG&E. You're seeing the influence of the little
6 bit higher population growth there. They are
7 growing at 2.1 percent per year. Both San Diego
8 and SoCalGas are growing at 2 percent per year.

9 PRESIDING MEMBER GEESMAN: Now, I'm
10 trying to think through that economic growth
11 assumption. If the inherent smoothness of your
12 modeling assumption for economic growth creates a
13 higher growth rate than we've seen historically
14 with similar economic growth, you're certainly not
15 predicting that economic growth in the future is
16 likely to be less choppy than it has been in the
17 past.

18 MR. DiGIOVANNA: Right, and actually I
19 should qualify that. It's not another -- probably
20 the most important variable in the residential and
21 commercial sector is weather. In our model we're
22 holding weather constant. So I'm not really
23 talking about it because it's not going to drive
24 any of these forecasts.

25 PRESIDING MEMBER GEESMAN: Okay.

1 MR. DiGIOVANNA: Historically, though,
2 if you were to look at changes in weather
3 patterns, too. I guess just knowing that the
4 growth rate that we're seeing here is going to be
5 higher than what people have seen, and it may
6 raise a question.

7 One explanation could be just the fact
8 that there is steady, you know, you don't have an
9 economic downturn that'll kind of suppress demand
10 and then have to have it worked back up.

11 The main thing, though, would also be
12 the weather. You know, the weather's not going to
13 stay constant. You're going to have years that
14 are below average that's going to put a damper on
15 gas demand.

16 PRESIDING MEMBER GEESMAN: Yeah, but if
17 I look back over the course of the last ten years,
18 shouldn't I have a comparable rate of growth? If
19 you've got weather held constant, and virtually
20 identical economic growth assumptions, shouldn't,
21 measured over a ten-year period, my commercial
22 natural gas demand going forward ten years grow at
23 roughly the same rate as it has going backward the
24 last ten years?

25 MR. DiGIOVANNA: Well, if you could go

1 backward ten years and hold weather constant, we
2 may see rates similar to what we're seeing here.

3 PRESIDING MEMBER GEESMAN: Okay, but you
4 don't backcast your model to test for that?

5 MR. DiGIOVANNA: No.

6 PRESIDING MEMBER GEESMAN: Okay.

7 MR. DiGIOVANNA: This next slide here
8 is, like in the residential, showing how
9 California compares to the western states and
10 provinces. Western states grow, again, about the
11 same rate, 2 percent per year. Western Canada,
12 with the lower economic growth assumption, grows
13 about .9 percent per year.

14 All right, gas demand for chemical
15 manufacturing in California. Overall chemical
16 manufacturing doesn't represent a very large
17 portion of the total gas demand in California.
18 Despite that, I mean the results are still
19 interesting.

20 You can see, different than the previous
21 forecasts we've seen, you'll see a lot more
22 variations in this forecast, and that's because of
23 price. One thing that came out of the model is
24 that in California we're still seeing positive,
25 despite high prices, we're still seeing positive

1 growth in all three utility areas for chemical
2 manufacturing.

3 The reason for that is that the overall
4 industrial production and the oil price have a lot
5 more influence on chemical manufacturing than it
6 does on the rest of industrial manufacturing. And
7 a lot of that has to do with the use of natural
8 gas as a feedstock. If alternative sources of
9 feedstock are also expensive then even though gas
10 prices are going to go up, the influence of the
11 other source of feedstock are going to weigh in.

12 And then in terms of just the overall
13 industrial production, because a lot of the
14 products that are manufactured in the chemical
15 manufacturing industries are used in the overall
16 industrial process. If there's growth in overall
17 industrial growth, that's also going to weigh
18 pretty heavily on the chemical side.

19 Conversely, on the nonchemical side you
20 can have growth beyond the -- in industrial
21 production, but it's not necessarily going to have
22 to come from gas-intensive industries.

23 PRESIDING MEMBER GEESMAN: So, this
24 slide basically captures divergence in your future
25 projections for gas prices versus oil prices?

1 MR. DiGIOVANNA: It's going to capture
2 differences in our gas forecast relative to the
3 oil. The oil price forecast from EIA, I believe -
4 - right, it's the high E case -- basically over
5 the forecast horizon drops a little bit initially
6 and then kind of comes back up.

7 So as time goes on, particularly in this
8 region here, there's more of an influence from the
9 higher. Even though at that point of the forecast
10 is actually where we're probably at our highest
11 point as far as natural gas prices go. That's
12 also happens to be right when the oil price
13 forecast is starting to come up.

14 PRESIDING MEMBER GEESMAN: And you're
15 using the EIA high case for that?

16 MR. DiGIOVANNA: The EIA -- the two high
17 cases. So a high and a really high, we just use
18 the high.

19 PRESIDING MEMBER GEESMAN: Okay.

20 MR. DiGIOVANNA: So, like I said there's
21 positive growth in all three utility areas. In
22 SoCalGas we're seeing growth of about .9 percent
23 per year. PG&E, about half a percent per year.
24 And then SDG&E, 1 percent per year, but I should
25 qualify that because they're going from 4 million

1 cubic feet per day to 5 million cubic feet per
2 day. So it's not like we're talking about a lot
3 of gas for that 1 percent.

4 And this is how we compare to the rest
5 of the west. The other western states are going
6 to be facing basically the same industrial
7 production that was used in California. They do
8 actually show a slight decline. The forecast is
9 essentially flat, it's about a decline of .1
10 percent per year.

11 In western Canada, however, with the
12 industrial production not as strong you're really
13 seeing the effect of the higher natural gas
14 prices, particularly at the end of the forecast.

15 And another thing that when we get to
16 the price section you'll see that the rising
17 prices tend to be actually the highest, at least
18 as far in the west, in western Canada. So you're
19 seeing that come out here in the forecast.

20 PRESIDING MEMBER GEESMAN: Now, rising
21 prices tend to be highest in western Canada?

22 MR. DiGIOVANNA: Well, -- I'm getting
23 ahead of myself. When we get to the wellhead
24 price forecast --

25 PRESIDING MEMBER GEESMAN: Okay.

1 MR. DiGIOVANNA: -- we're showing at the
2 end of it that Alberta, I shouldn't just say
3 Alberta, it's all western Canada wellhead prices
4 actually end up increasing a lot more than other
5 production areas of the west.

6 PRESIDING MEMBER GEESMAN: Okay.

7 MR. DiGIOVANNA: And we'll get into
8 that.

9 Okay, so for the industrial forecast for
10 nonchemical, in this case we are seeing a lot more
11 influence from the rising natural gas prices,
12 particularly at the end of the forecast. All
13 three utility service territories are showing
14 actually negative growth. Not very much.

15 SoCal and PG&E decrease at about .3
16 percent per year. San Diego decreases .2 percent
17 per year. But mainly what you're seeing here is
18 the influence of the higher natural gas prices,
19 particularly at the end of the forecast.

20 And, again, this is how it compares to
21 the rest of the west. The negative growth rates
22 that we see are actually very similar to what
23 we're seeing in California. Western states
24 declined at about .2 percent per year, and western
25 Canada declines at .3 percent per year.

1 All right, this slide here, this is just
2 another look at the forecast that Lynn showed you
3 earlier. This is for the noncogeneration portion
4 of the TEOR gas demand. Like you brought up
5 earlier, there are some questions that come up
6 with this in terms of, you know, we've seen in
7 recent years declining oil production,
8 particularly out of southern California, the Kern
9 County area.

10 But is that because the resources just
11 weren't economical to recover, or because the
12 resources just aren't there. So, this is
13 something I wanted you to look at because if it
14 was just for economic reasons with higher oil
15 prices then you'd probably expect to see a rising
16 forecast here.

17 PRESIDING MEMBER GEESMAN: And this is
18 just material that you got from the electricity
19 demand office? Or did you independently
20 forecast --

21 MR. DiGIOVANNA: No, no, we didn't do
22 this independently. We actually took this from
23 the demand analysis office.

24 PRESIDING MEMBER GEESMAN: Okay.

25 MR. DiGIOVANNA: All right, this is the

1 forecast for bitumen extraction and upgrade in
2 Alberta. This is somewhat a source of explosive
3 growth up in Alberta. I mean particularly with
4 higher oil prices there is increasing effort to go
5 and recover those resources.

6 The methods used to do that, either you
7 can, if it's closer to the surface you can mine it
8 and then separate the bitumen from the rest of the
9 oil sands. Or if it's deeper, you could either
10 use the cyclic steam process, or you can use the
11 gravity-assisted process.

12 Cyclic steam process is the older of the
13 two. Probably presently a lot more common of the
14 two, and also the more energy intensive of the
15 two. In 2001 is when they started using the
16 steam-assisted gravity recovery method. And over
17 time, and this probably explains the fairly flat
18 forecast at the end of the forecast horizon, that
19 will probably end up starting to, you know, more
20 and more replace the cyclic process.

21 PRESIDING MEMBER GEESMAN: And where did
22 your assumptions for bitumen extraction come from?

23 MR. DiGIOVANNA: This is from Canada's
24 National Energy Board. This was their, basically
25 their energy report, I believe this is -- I'd have

1 to double check, I'm sorry. I believe it's a 2003
2 report.

3 They came out in 2004 with a report just
4 on the oil sands in Alberta. Unfortunately, they
5 didn't provide a gas demand forecast in that. So,
6 this is something we'll have to check into more to
7 see if because of the increasing use of the steam-
8 assisted gravity recovery, if that's going to
9 change their forecast.

10 PRESIDING MEMBER GEESMAN: I guess is
11 there any way to corroborate the bitumen
12 production assumptions that underlie your
13 projected natural gas demand with what a current
14 projection of bitumen production might be?

15 MR. DiGIOVANNA: Well, this is something
16 that we could probably do it with some help. I
17 mean it would be difficult to do sitting here just
18 not knowing enough about the industry, itself, to
19 try to come up with a method to forecast it.

20 I think that if we were to try to
21 collaborate more with the folks up in Alberta that
22 we probably could get some assistance on this and
23 see how that's going to change. See if their
24 projections for the amount of bitumen they plan on
25 recovering have changed. If they see a widespread

1 move to the more efficient process, if that's
2 going to change.

3 And the other thing with the bitumen
4 extraction is that they're using natural gas to
5 upgrade it, add hydrogen to it, to be able to make
6 synthetic crude. So, see if there's any changes
7 there, if they're planning on using another
8 feedstock or anything like that.

9 PRESIDING MEMBER GEESMAN: Yeah, I think
10 the obvious concern is that perspective may be
11 different in a \$60 a barrel world than it was in a
12 \$40 a barrel world.

13 MR. DiGIOVANNA: Right. And Alberta has
14 been, or folks up in Alberta have been
15 aggressively trying to recover this anyway, I mean
16 prior to seeing oil go up to \$60. How much more
17 they could do, I don't know. So this is something
18 that we would want to follow up on.

19 Because, as you can see, ending the
20 forecast period at over 1200 million cubic feet
21 per day, I mean that's --

22 PRESIDING MEMBER GEESMAN: That's a lot
23 of gas.

24 MR. DiGIOVANNA: Yeah, that's a lot of
25 gas. So, this is an area that we probably need to

1 get smarter on over time.

2 MR. MAUL: Commissioner, again, we have
3 a parallel study that was mentioned earlier with
4 the Western Interstate Energy Board. We have a
5 team that's already been established we're working
6 with on that study. And which includes
7 participants from Alberta and from British
8 Columbia. So, we already have regular contact
9 with those folks and we'd be happy to do a
10 followup on that and should be able to get some
11 pretty good data.

12 PRESIDING MEMBER GEESMAN: Yeah, I think
13 that would be helpful.

14 MR. MAUL: Okay, we'll do --

15 COMMISSIONER BOYD: Their people have
16 been here quite a bit, but purely on the oil side.
17 And I don't know if we're correlating back and
18 forth internally on that.

19 The question I had, Mark, though is
20 there's been extreme variance between the EIA
21 projections of this recovery and the Canadian
22 industry's projections for quite some time.

23 EIA, in the last year or so, maybe it's
24 been two years, year and a half to two years now,
25 started including some proportions of this in

1 their projections for the future.

2 Do you know what the variance might be
3 between the estimate you have here, which is from
4 the Canadians, versus what EIA is carrying? Or is
5 there a variance anymore?

6 MR. DiGIOVANNA: You know, to be honest
7 I haven't actually seen the forecast that EIA has
8 for bitumen extraction in Alberta. With the
9 annual energy outlook, they are -- that's limited
10 strictly to the United States. So I haven't
11 actually seen any other forecasts of that.

12 We have seen transCanada pipeline has
13 also provided forecasts to us, which we have
14 looked at. And in the past they've been fairly
15 similar. I think that transCanada might have a
16 little bit more progressive view of how much the
17 SAGI process will be used in the future, which
18 might end up dampening the growth in the gas
19 demand.

20 COMMISSIONER BOYD: Thank you.

21 MR. DiGIOVANNA: Just a couple left.
22 The projections for gasoline and for electricity
23 generation in California. The forecasts here that
24 we have right now is, I think, still in the
25 development process. Might not change a lot from

1 this.

2 Right now we're showing about 1 percent
3 per year growth in SoCalGas; .7 percent in PG&E.
4 A big jump to 3.9 percent in SDG&E, but that's
5 really just because Otay Mesa comes online over
6 the forecast horizon.

7 The part that's a little surprising is
8 that we're showing the off-system power plants
9 actually declining gas demand over the forecast
10 horizon. So this is something that we'll want to
11 look into, and probably just continue the
12 iteration process. I think that'll work that out.

13 PRESIDING MEMBER GEESMAN: What are
14 those?

15 MR. DiGIOVANNA: These are the power
16 plants that are operating off the Kern River
17 pipeline, the Blythe Power Plant, which is
18 operating directly off El Paso. There are some
19 power plants that are using just dedicated
20 California production to operate.

21 So basically they're the power plants
22 that aren't taking any gas from the utility
23 system.

24 PRESIDING MEMBER GEESMAN: Okay.

25 MR. DiGIOVANNA: And this is how

1 California compares to the west. We're still
2 using more gas for power generation than the rest
3 of the west. In fact, I'm not sure exactly just
4 by eyeballing it, but probably more than the
5 western states and western Canada combined.

6 You do see some variation over time on
7 the western states. There are other factors
8 influencing this such as nongas-fired power plants
9 coming online taking away share from the gas-fired
10 generators. And also a move to go towards more
11 renewables.

12 PRESIDING MEMBER GEESMAN: What accounts
13 for the variation of the California numbers?

14 MR. DiGIOVANNA: The California numbers,
15 a lot of it is prices change in California
16 relative to other areas, we might end up start
17 taking more electricity from outside the state
18 versus generating inside the state.

19 Also, we are assuming that as we get
20 closer to meeting the RPS standards, you know,
21 that is going to add generating assets that won't
22 use gas.

23 PRESIDING MEMBER GEESMAN: Well, look at
24 the dip, for example, in 2011.

25 MR. DiGIOVANNA: 2011 is, I believe,

1 Intermountain 3.

2 PRESIDING MEMBER GEESMAN: Angie, why
3 don't you come up and take a microphone.

4 MS. TANGHETTI: I'm Angela Tanghetti
5 with the electricity analysis office. And we did
6 assume that beyond 2010 that more coal-fired
7 resources are going to come into the resource mix
8 in the west, as well as natural gas prices do
9 drive these results, as far as some dips in
10 California.

11 PRESIDING MEMBER GEESMAN: And tell me
12 how the price function works in terms of the
13 results that you gave the gas demand modelers.

14 MS. TANGHETTI: Price is a component of
15 how the power plants are dispatched. And, again,
16 regional differences in natural gas will dictate
17 how power flows, and how much from one region to
18 the other in the model.

19 PRESIDING MEMBER GEESMAN: So if the
20 cost of gas-fired generation in California goes up
21 relative to the cost of other generation outside
22 California, you would expect a greater level of
23 import from outside California to displace that
24 gas-fired generation in California?

25 MS. TANGHETTI: Correct.

1 PRESIDING MEMBER GEESMAN: Okay, thank
2 you.

3 MR. DiGIOVANNA: The last slide here is
4 to show you how we've broken up Mexico. I figured
5 out last night while I was putting this together
6 that although it shows that they're all on a
7 common scale, they weren't on a common scale when
8 I sent this to get the map made. So disregard
9 this chart.

10 But just to let you know what's going on
11 with Mexico, basically all of Mexico we're looking
12 at a growth in demand from about 6.7 bcf per day
13 to 9 bcf per day by the end of the forecast
14 horizon.

15 In Baja, which is probably the greatest
16 concern to California, gas demand will grow from
17 380 million cubic feet per day to 688 million
18 cubic feet per day. And just let you know, the
19 source for this forecast was the NPC; this is the
20 forecast that they were using in their NARG, the
21 NARG model runs that they were doing. And we just
22 took that and put that straight into ours.

23 PRESIDING MEMBER GEESMAN: And that's
24 how the regional groupings are handled, as well?
25 They define the region?

1 MR. DiGIOVANNA: Yes.

2 PRESIDING MEMBER GEESMAN: Dave, we
3 might want to compare this, and I'm not certain
4 that it's comparable, but we might want to compare
5 the Baja numbers with anything that comes out of
6 the order energy paper that the staff is working
7 on.

8 MR. MAUL: Okay, will do.

9 MR. DiGIOVANNA: Any questions?

10 MR. TOMASHEFSKY: Mark, I have a couple,
11 actually going back to the elasticity parameters.

12 MR. DiGIOVANNA: Um-hum.

13 MR. TOMASHEFSKY: Recognizing that this
14 is the first time we've put it in the model, which
15 Ken Medlock had discussed at the October workshop
16 and we went through a lot of the discussion there.
17 And going back to what Commissioner Geesman was
18 homing in on with respect to population and
19 household income.

20 The elasticities contained here are not
21 regional specific; they're based -- is that
22 correct, it's a one --

23 MR. DiGIOVANNA: The elasticities --

24 MR. TOMASHEFSKY: -- formula fits all
25 for each of the regions?

1 MR. DiGIOVANNA: Yeah, the formula,
2 itself, the actual elasticity parameters are the
3 same for all regions.

4 Now, the actual data that goes into
5 those is region-specific in terms of population
6 and weather. For income, like I mentioned
7 earlier, we just used GDP both for United States
8 and for Canada. And for -- yeah, I think those
9 are the only region-specific variables.

10 And the other thing that I didn't
11 mention here is that when Ken did this work for
12 all these formulas, there is a constant term. The
13 constant term is actually calibrated to be region-
14 specific.

15 So, each region has a function that the
16 elasticities are all the same, the constant is
17 different, and the actual values that go in in
18 terms of weather and population are also region-
19 specific.

20 MR. TOMASHEFSKY: So the constant term
21 now becomes your zero point, as far as that's not
22 a variable in terms of what --

23 MR. DiGIOVANNA: No, it's not a
24 variable.

25 MR. TOMASHEFSKY: So if you look at

1 things, for example, when you look at population
2 and you make the assumption that if your driver is
3 population growth and is nice r-squared there, on
4 a continental basis when you start looking at
5 trends and growth in California and looking at the
6 households kind of growing east and the demand
7 growing in a little bit of a disproportionate
8 level, you may have some variations from what you
9 might expect to see the r-squared to be for, say,
10 California.

11 So the equation may not fit quite as
12 nicely for California as opposed to other parts of
13 the country.

14 MR. DiGIOVANNA: Right, I mean, that
15 might be something that once we're done with this
16 process that we might want to look at and see how
17 that changes if we were to look at just California
18 by itself to see how it reacts to these variables.

19 Obviously, under the timeframe we were
20 working with there wasn't a whole lot of time to
21 go in and try to customize this too much. I mean
22 it was customized to some degree and definitely
23 updated. But, you know, trying to come up in
24 having a lot more statistical work done to go
25 behind this just within the timeframe that we were

1 dealing with, it just wasn't practical.

2 MR. TOMASHEFSKY: Right, and I think
3 what Ken said in October is that there would be an
4 expectation that these elasticities would be
5 updated every forecast. And so I guess you could
6 take that one step further and say you'd also
7 reconsider whether there needed to be adjustments
8 made, say regional or other variables be added to
9 the equation.

10 MR. DiGIOVANNA: Right.

11 MR. TOMASHEFSKY: Okay. Thanks.

12 MR. DiGIOVANNA: Any other questions?

13 PRESIDING MEMBER GEESMAN: Any questions
14 from the audience for Mark? Great. Thanks a lot,
15 Mark.

16 MR. MAUL: Before we get back to Jairam
17 again, let me just make a note for the audience
18 that we do have blue cards here. We encourage
19 anybody who wishes to talk to please fill one out
20 and we can make sure we take you in order. I know
21 there's some prepared presentations, but also if
22 anybody has any questions, comments of any kind
23 that you think of as you're going along, we'll be
24 happy to pass that blue card for you.

25 MR. GOPAL: Is Richard Hendrix here?

1 Okay. Next we'll have the demand portion of the
2 discussion from PG&E. Richard and Herb, you're
3 the ones who will be talking for PG&E and
4 SoCalGas. From your package we will focus only on
5 the demand slides now, and then we will continue
6 with the rest of it during the second half of the
7 morning session.

8 So, please come on up.

9 MR. HENDRIX: Jairam, thank you for
10 producing those slides electronically. I was
11 struggling on how to pass these out. It looks
12 like I will not have to do so.

13 Okay, --

14 (Whereupon, at 10:31 a.m. a fire drill
15 commenced, concluding at 10:55 a.m.)

16 MR. GOPAL: Before we begin with PG&E
17 presentation I want to make sure that we are all
18 back here and none of us are lost in the park.
19 Please take a look at your right and left to make
20 sure your partner is still here.

21 (Laughter.)

22 MR. GOPAL: Okay, Richard, the floor is
23 yours.

24 MR. HENDRIX: Thank you, Jairam. I'm
25 Richard Hendrix from PG&E. I am PG&E's non-EG,

1 non-cogen gas demand forecaster. So I'm going to
2 be speaking actually to Lynn Marshall's forecast.

3 Let me just start out by saying that,
4 just to make sure that everybody knows what's
5 actually in this forecast and presumably what's in
6 Lynn's as well, this includes no off system
7 throughput; includes no shrinkage; includes no
8 cogen; includes no EG gas demand. This is simply
9 end user gas demand, which would be residential
10 and nonresidential.

11 Let me direct your attention to the
12 first slide here, and that's simply a comparison
13 between the summation of res and nonres for PG&E
14 and CEC respectively. And you can see the two
15 forecasts are very close up through about 2011 and
16 then there's a divergence after 2011 with the CEC
17 forecast being a little bit higher than the PG&E
18 forecast.

19 Over that ten-year span from 2006 to
20 2016, the average difference on an annual basis is
21 .6 percent per year. And that's, as we go through
22 this, we'll see that's pretty much all a function
23 of differences in projective nonresidential gas
24 demand.

25 If you take a look at the second or

1 third slide, rather. This is -- this chart shows
2 a comparison of the CEC and the PG&E residential
3 forecasts. Let me just mention a little bit about
4 the efforts that went into making the comparison
5 between the two.

6 It's rather challenging in that the way
7 PG&E bundles up their various types of demand is
8 very different from the way the CEC does it. The
9 CEC does it by (inaudible) and PG&E does it by
10 customer class. And customer class is aggregation
11 of various rate schedules.

12 So, for instance, about the only entity
13 that we have in common is residential. There's a
14 slight difference there, but basically that's
15 about the only class that we can look at sort of
16 straight up.

17 We do forecasts for two different
18 commercial classes, for two different industrial
19 classes, and then we have a wholesale forecast.
20 And the CEC does it, as I mentioned before, by
21 (inaudible). And given that difference in
22 aggregation, about the only thing that one can do
23 is to separate res from nonres and make the
24 comparison on that basis.

25 So, being able to reconcile differences,

1 at least on the nonres side, is a little bit
2 challenging in that you can't go down and look at
3 what we consider to be industrial gas demand, for
4 instance, versus what the CEC believes is
5 industrial gas demand, because it's not
6 necessarily the same animal. Same is true for
7 commercial.

8 So, that's why, as you go through this,
9 I mean there's really only going to be two
10 comparisons that are made, residential and
11 nonresidential.

12 Complicating that comparison is the fact
13 that there's two very different methodologies that
14 lie behind the development of the two forecasts.
15 Lynn uses end user models for the most part; I
16 guess I heard her say that I guess ag and one
17 other sector she actually does an econometric
18 model. We use econometric models exclusively for
19 our forecasts.

20 So, given that difference it's a little
21 bit difficult to say, oh, okay, so what is your
22 coefficient for this variable, or what variables
23 are you using.

24 So, with that backdrop, and let me tell
25 you a little bit about how gas through-put breaks

1 down for our service territory. If you include EG
2 and cogen gas demand in the total, the total off
3 system, and normalizing as well as one can for
4 hydro conditions and temperature conditions,
5 generally res is about 30 percent of the total of
6 gas demand for us. EG/cogen is 36 percent or so.
7 And other nonres is 34 percent.

8 We do have another category, wholesale
9 gas demand, which comes from six wholesale
10 customers in our service territory for whom we
11 transport gas. We don't procure it, but we
12 transport it for them. That's, in total, pretty
13 small. It's maybe half a percent of total
14 onsystem gas demand.

15 And the only reason I even want to bring
16 up wholesale here is because there is a
17 discrepancy, so to speak, between the data that
18 the CEC has received from a couple of the
19 wholesale gas customers and our data for those
20 customers. And I'll touch on that in a moment.

21 MR. GOPAL: And, Richard, when you say
22 the wholesale transportation is half a percent of
23 onsystem, you're not including any offsystem in
24 that data.

25 MR. HENDRIX: I am not including any

1 offsystem in that total, no. So, there's nothing
2 going to southern California, Kern River Station,
3 Southwest Gas Exchange Agreement. Those
4 categories are all excluded from these totals.

5 Anyway, so let me just return to this
6 comparison of the residential gas demand forecasts
7 for CEC and PG&E. They're remarkably close. And
8 I mean I -- it surprises me as to how close they
9 are, given the difference in methodologies.

10 There were a couple of data adjustments
11 I had to make, which I'll mention in just a
12 moment. But for any given year that you look at
13 in this ten-year period from 2006 to 2016, the
14 most the forecast in that year diverges one from
15 the other is 1 percent.

16 Growth rates are remarkably similar.
17 They're, you know, roughly a percent per year.
18 It's not shown on this chart, but from 2003 to
19 2006 there is a rather large increase for going
20 from the base year of 2003 to the first forecast
21 year of 2006. It's about 1.5 percent. And that's
22 basically because 2003 was a warmer than normal
23 year. And what that translates to in a core
24 environment and residential environment is less
25 gas is used for heating purposes.

1 There's not much more I can say about
2 Lynn's forecast. I think it's reasonable.

3 PRESIDING MEMBER GEESMAN: Recognizing
4 the difference in methodologies, are there any of
5 the input assumptions that she's used that you are
6 aware of that you would consider to be
7 unreasonable?

8 MR. HENDRIX: We haven't gone into great
9 detail. I know in general some of the variables
10 Lynn has used. I don't think they're terribly
11 dissimilar than ours. I don't know what the
12 difference in the level of those variables are.

13 But basically I'm using, for the
14 residential equation, heating degree days for
15 PG&E's service territory. Some seasonal dummy
16 variables; a real price variable; a time trend
17 variable that picks up sort of a long-term
18 improvements in building shell improvements and
19 efficiencies and appliance efficiencies. And
20 households.

21 And I think some, if not all, of those
22 variables are also picked up in Lynn's end use
23 models. But as I say, we haven't actually talked
24 about any given year, what the value of one of
25 those variables looks like for a given year.

1 MR. GOPAL: When you use the real price
2 as a variable, do you have a price input that you
3 provide into your equations or --

4 MR. HENDRIX: I'm sorry, Jairam, do I
5 have a what?

6 MR. GOPAL: Is there a natural gas price
7 for residential customers input in your equation?

8 MR. HENDRIX: There is. This is a
9 constructed variable using one component as
10 transportation costs; the big driver cost, of
11 course, is the commodity cost. We get that
12 forecast from Gas Seer. It's a private vendor.

13 In general, as you go through 2016, I
14 mean it's actually Seer only goes out a few years,
15 and then I had to escalate the variable. But if
16 you go out, say, to 2008, it's between \$5 and \$6
17 on a nominal basis. I convert it into real terms
18 when I input it into the model.

19 Let me just briefly, and I mean briefly
20 here, because this can get very tedious very
21 quickly. And I want to just mention this mainly
22 for Lynn's benefit about a couple of adjustments
23 here.

24 There is a certain segment of what we
25 consider core gas demand that in Lynn's data is

1 counted as residential and ours is counted as
2 commercial. And it amounts to roughly 8 million
3 therms per year. And it's basically gas uses for
4 common areas, residential common areas, laundry
5 rooms, swimming pools, things of that nature.

6 So I've taken those therms and moved
7 them from commercial nonresidential over to our
8 residential side to be consistent with the data
9 that Lynn is using.

10 And, Lynn, the 8 million therm number
11 simply comes from the differences between the
12 schedule 2 and schedule 3 1308 report.

13 The other adjustment here is one that
14 Lynn and I have talked about, and it's this
15 surprising difference in throughput that the City
16 of Coalinga is reporting to the CEC. They are
17 reporting it on the residential side. They use
18 about 8 million therms per year.

19 We bill them, it's a very constant
20 stream of therms, we bill them for no more than 2
21 million per year. Now, I mean it's conceivable,
22 since Coalinga is located down relatively close to
23 Bakersfield, that for the difference, the 6
24 million therm difference, that's throughput that
25 they're getting directly off the Kern River

1 pipeline. But I wouldn't necessarily know that.

2 In any case, I have removed that 6
3 million therm total from the CEC residential
4 forecast. Just for comparison purposes between
5 our forecast and the CEC's.

6 Okay. The next slide shows a comparison
7 of PG&E's and CEC's nonresidential gas demand
8 forecasts. And again, on the CEC side it's by
9 (inaudible); for us it's by customer class
10 aggregated together for this purpose.

11 There is both temperature-sensitive and
12 nontemperature-sensitive gas in here, but it's
13 primarily nontemperature-sensitive.

14 As you can see from the chart the two
15 forecasts are not terribly different for the first
16 four years or so of the forecast horizon. And
17 then they diverge considerably starting at 2010.
18 Not exactly sure what's causing that.

19 The other interesting thing I noticed
20 about the CEC forecast was that going from 2003 to
21 2006 it actually fell by .6 percent per year in
22 that period. I'm not exactly sure what's causing
23 that drop to occur.

24 I mean in our estimation this sector
25 overall is very flat. I mean it's dominated by,

1 if you think of it primarily as a combination of
2 commercial gas demand and industrial gas demand,
3 it's dominated by industrial gas demand. And
4 that, in turn, is dominated by demand from large
5 manufacturing firms.

6 PRESIDING MEMBER GEESMAN: What sectors?

7 MR. HENDRIX: Interesting you should
8 ask. Demand for industrial gas in our territory
9 is highly concentrated. Fully half of that demand
10 comes from two sectors, oil refineries and food
11 processors. About a third comes from oil
12 refineries and maybe 20 percent comes from food
13 processors.

14 Eighty percent of the throughput comes
15 from eight industries. Now, the percentages go
16 downhill very quickly, but I'll just throw them
17 out here. For oil refineries it's roughly 33.3
18 percent; food processing 20 percent; stone, clay
19 and glass, what used to be called the old SIC
20 environment, stone, clay and glass 10 percent; 4
21 percent for chemical plants; 4 percent for
22 educational establishments, you know, large
23 universities and colleges; 3 percent from health
24 care institutions like hospitals; 2 percent from
25 paper manufacturing firms; and 2 percent from oil

1 and gas extraction firms.

2 You add all those up, it's roughly about
3 80 percent of the total; and so the additional 20
4 percent comes from a large range of industries.

5 PRESIDING MEMBER GEESMAN: So when you
6 see stagnation across the overall industrial
7 customer class, which sectors do you see
8 stagnating?

9 MR. HENDRIX: Pretty much everything
10 except oil refineries. And I'll just -- let me
11 throw out a couple of numbers here.

12 For entirely different presentation that
13 we put together a month or so ago, looking at
14 industrial customers and how their use has changed
15 over their time, or how their numbers have changed
16 over time, I looked at, first of all, the average
17 number of customers in these sectors from 1994 to
18 2001. And then looked at the number from 2002 to
19 2004.

20 Paper manufacturing customers fell from
21 32 to 26 between those two periods. Stone, clay
22 and glass customers fell from 48 to 41.
23 Temperature sensitive customers fell from 236 to
24 209. I did have -- food processors fell, I think,
25 by around 20. I'm sorry, I don't have that in my

1 notes here.

2 PRESIDING MEMBER GEESMAN: Did volumes
3 to those sectors also fall? I mean might there
4 have been some consolidation within those
5 industries so that your customer count went down,
6 but your sales stayed the same?

7 MR. HENDRIX: We looked at -- or I
8 looked at sales per customers, as well. Okay, I'm
9 sorry, let me address that in just one moment.

10 Food processing firms dropped from 236
11 to 189. Paper manufacturing firm customers
12 dropped from 32 to 26. The only sector for which
13 the number of customers remained relatively
14 constant was oil refineries, which we basically
15 have about 13 in our service territory.

16 With respect to consumption per customer
17 for those various industries, paper manufacturing
18 gas sales per customer has fallen year after year,
19 looking back through 1994. It plummeted by 30
20 percent in 2003.

21 Food processing sales per customers
22 dropped by 6 percent over the two periods.
23 Chemical industry sales per customer has decreased
24 by 15 percent between the two periods. Only
25 refiners and stone, clay and glass customers

1 consumption per customer has not declined.

2 Presumably stone, clay and glass sales are as high
3 as they are only because of the boom in
4 construction in northern California.

5 I think there's probably other industry-
6 specific factors that are affecting some of these
7 sectors. Food processors in our service territory
8 have fallen, we believe, because of NAFTA. A lot
9 of these firms have left the Central Valley and
10 probably have relocated to Mexico. But that's
11 nothing more than a hypothesis on our part.

12 Paper manufacturing has probably fallen
13 only because of the decline in harvestable acreage
14 in northern California and the Pacific Northwest.

15 Overall, the number of customers,
16 industrial customers, has fallen -- it peaked in
17 1999 at about 1150. Since then it's dropped by 15
18 percent -- now these are customers. We don't know
19 how many of those have gone out of business and
20 how many have simply moved their operations. And
21 we just don't collect those data. All we know is
22 that they're gone.

23 More general reasons for that decline
24 probably are relatively high natural gas prices.
25 And that's probably going to vary by industry as

1 to how much that impacts a given customer. And,
2 you know, just this general secular transition
3 from a manufacturing economy to a service oriented
4 economy.

5 Let me talk a little bit, again I want
6 to try to keep this brief because I know this is
7 not terribly exciting, but just about some of the
8 dated issues associated with nonresidential gas
9 demand.

10 It appears to us that there's some
11 double counting here. Lynn's took the Cal Gas
12 Report numbers from the 2004 Cal Gas Report and
13 used that as sort of the default 2003 throughput
14 number for 2003. I think that was the right thing
15 to do. I agree totally with that logic.

16 Having said that, I think there's
17 probably a couple of technical aspects of that
18 that I would differ with. The first one is the
19 Cal Gas Report reports usage on a cubic foot
20 basis. These forecasts are all developed on a
21 therm basis. So that conversion needs to be
22 converted from the -- or the throughput from Cal
23 Gas Report needs to be converted into therms.

24 As I understand it, I think Lynn used a
25 1.02 percent conversion factor. I think it's

1 probably more reasonable to use 1.015. And when
2 you do that the base year data falls somewhat,
3 somewhat, 12 million therms per year.

4 There's also this common area issue --

5 PRESIDING MEMBER GEESMAN: Why do you
6 think the lower conversion factor is the
7 appropriate one?

8 MR. HENDRIX: We collect these data both
9 on a cubic foot basis and on a therm basis, and
10 when you make that comparison, at least for these
11 customers in our service territory, the 1.02 seems
12 a bit high.

13 The common area issue, the one I alluded
14 to before, where this throughput was moved from
15 commercial sector over to the residential sector
16 in our forecast, just to be able to make a
17 comparison on the res side, if you benchmark to
18 the Cal Gas Report data for 2003, in that
19 nonresidential data are all those therms, which
20 are over in the res sector at the moment.

21 So if you add up all those
22 nonresidential therms in the Cal Gas Report you're
23 actually including those 8 million therms that are
24 already over in the res sector. So, that should
25 be excluded.

1 Let me just mention also that this
2 comparison that I made is taking into account all
3 of these adjustments that I'm going through here.
4 That's post these adjustments; that's not pre.

5 Let's see, the other couple of
6 adjustments, Lynn and I talked about this a couple
7 times. What the CEC considers the mining sector
8 for PG&E's service territory, is actual throughput
9 that we lost over ten years ago. These are from
10 EOR type customers down in the San Joaquin Valley,
11 near Bakersfield. And they take usage directly
12 off the Kern River pipeline. We just -- they're
13 not our customers.

14 Roughly 95 percent of the mining sector
15 forecast in the CEC's projections stem from that
16 throughput.

17 And last, there's two issues related to
18 these wholesale customers. Apparently Coalinga
19 reports that they use 5 million therms per year
20 for nonresidential use. Now we personally don't
21 know the customer base for these wholesale
22 customers. I presume it's mostly residential, and
23 wouldn't preclude the possibility of there being
24 some nonresidential usage in there.

25 I do know, as I mentioned before, that

1 we don't transport any more than 2 million therms
2 per year for Coalinga. That's already over the
3 residential forecast. And so on the res side,
4 these 5 million therms that they're reporting that
5 they use, I removed that from the CEC forecast.

6 And lastly, one additional wholesale
7 customer issue and that is for the City of Palo
8 Alto. We bill them for basically 33 million
9 therms per year. And it's relatively temperature
10 sensitive, but on a temperature-normalized basis
11 it's roughly 33 million per year.

12 Those 33 million therms are over on the
13 residential side above the PG&E forecast, as well
14 as the CEC forecast. Palo Alto's reporting to the
15 CEC that they use 21 million therms in 2003 for
16 nonresidential end users that they have. I just
17 removed that from the CEC forecast, just so we
18 could have an apples-to-apples comparison.

19 So those are the data issues associated
20 with nonresidential throughput. And as I say,
21 it's too bad we can't drill down, I mean one
22 possibility is if we have, especially on the
23 nonres side if we're using variables in common we
24 can just see what the growth rate on those
25 variables would be to see what might be driving

1 this difference between the two forecasts in the
2 post 2011, 2012 period.

3 Any questions?

4 PRESIDING MEMBER GEESMAN: Richard,
5 thank you very much.

6 MR. HENDRIX: Sure.

7 PRESIDING MEMBER GEESMAN: It was quite
8 helpful.

9 MR. HENDRIX: And I just want to thank
10 both Lynn and Andrea for this information you
11 folks have given me to be able to do this.

12 MR. GOPAL: Next we will have Herb
13 Emmrich from Sempra Utilities.

14 MR. EMMRICH: Commissioner Geesman,
15 Commissioner Boyd and staff. We appreciate the
16 opportunity to present our view of the forecast
17 presented by the staff of the Commission.

18 I'd like to first say it's a very
19 comprehensive study and they've done an extremely
20 good job. We do have some differences; I'd like
21 to discuss those.

22 Overall the staff's report forecast of
23 demand growth is generally about 1 percent higher
24 than our forecast. And when we look at the data
25 it appears that we take a ten-year view of energy

1 efficiency programs that are mandated by the
2 Public Utilities Commission, and the staff is
3 looking at the first three years, 2006, 2007, 2008
4 only.

5 PRESIDING MEMBER GEESMAN: This is a
6 similar issue that we experienced in the
7 electricity demand forecast.

8 MR. EMMRICH: That's right.

9 PRESIDING MEMBER GEESMAN: So we are
10 familiar with that difference.

11 MR. EMMRICH: Okay. So, we would
12 appreciate it if there would be some kind of
13 consistency in how we do these forecasts, because
14 we're mandated to subtract out the --

15 PRESIDING MEMBER GEESMAN: Right.

16 MR. EMMRICH: -- gas goals, so that
17 would remove basically everything of a difference
18 overall between our forecast and the staff's
19 forecast.

20 We can go to the individual markets.
21 Residential market is very very similar; and the
22 difference is, you know, the energy efficiency,
23 especially out of time.

24 On the CNI market segment we do have
25 quite a bit of difference. We're targeting more

1 and more of the energy efficiency dollars at the
2 CNI market, especially at larger customers. In
3 previous years SoCalGas did not have a noncore
4 program targeted at commercial/industrial
5 customers. And in this program cycle we are, and
6 will continue to do so. So we expect to get more
7 bang for the buck by looking at noncore customers.

8 PG&E, the way I understand it, has
9 always done that. And San Diego Gas and Electric
10 has also had noncore programs. But this will be
11 the first time that we've had noncore programs for
12 SoCalGas.

13 Again, if you take into account the
14 energy efficiency differences, I think the
15 forecasts are very similar.

16 Electric generation, we're also very
17 similar. We have different starting dates, but
18 the end dates, as you can see, is almost
19 identical. We are working with staff to find out
20 exactly what's in the forecast with the CEC and
21 us. There's some possible difference on the
22 cogeneration units that we include, and are not
23 included, using it for electric generation versus
24 thermal applications.

25 In the San Diego area again there's a

1 slight difference in the forecast. And we
2 attribute that to the energy efficiency
3 assumptions.

4 The residential market is almost
5 identical, but as you can see there's a difference
6 in starting points. And that may be because the
7 assumption that we have is looking normalized
8 weather data only throughout the forecast period.
9 And we'll work with staff to at least get the
10 starting points the same. But it looks like the
11 growth rates are identical.

12 On the commercial/industrial side, again
13 we will be targeting more on the larger
14 commercial/industrial customers, getting more bang
15 for the buck. And that should slow down the
16 growth quite a bit. So there is a difference in
17 forecast, and hopefully we can work that out. We
18 can provide the information on the customer
19 groupings that we have targeted and the therm
20 savings that we have filed with the Public
21 Utilities Commission.

22 Electric gen, the same kind of thing
23 there. Possible differences on which cogen plants
24 are in and out, and how you account for those
25 therms. As you see, the endpoint is almost

1 identical by 2016. We pretty much have the same
2 view.

3 The chart, page 10, if you look at the
4 chart, you know, the forecast growth rates and so
5 on are almost the same overall for SoCalGas. But
6 that gap, because the energy efficiency savings
7 that you have, they accumulate. You know, once
8 you make an investment it's there for the next 10
9 years, 15 years, 20 years depending on the
10 measure. That doesn't go away, so you have the
11 accumulation and this is why you have the little
12 gap developing. But as you can see, the general
13 trend rate is not that different.

14 For San Diego Gas and Electric you have
15 the same story. We have generally the same trend
16 rate, but our forecast includes the energy
17 efficiency, and therefore it's somewhat lower.
18 And we would appreciate it if we could resolve
19 that issue maybe at the higher level --

20 PRESIDING MEMBER GEESMAN: It's in front
21 of us. We understand the dimensions of it and we
22 will address it in our draft report in September.

23 MR. EMMRICH: Okay, thank you very much.
24 And especially thanks to Lynn Marshall and Angela
25 Tanghetti for working with us. You have a great

1 team, and we really appreciate working with them.
2 Thank you.

3 PRESIDING MEMBER GEESMAN: Thanks very
4 much, Herb.

5 MR. EMMRICH: All right.

6 PRESIDING MEMBER GEESMAN: Jairam, this
7 is a logical breakpoint. I'd like to give Joe
8 Sparano an opportunity to address us. He's got a
9 conflict at noon.

10 MR. GOPAL: Sounds like a perfect
11 opportunity.

12 PRESIDING MEMBER GEESMAN: Okay. Joe.

13 MR. SPARANO: Thank you, Commissioner
14 Geesman. Good morning; my name is Joe Sparano;
15 I'm President of the Western States Petroleum
16 Association or WSPA.

17 We appreciate this opportunity to
18 provide WSPA's comments to the Commission. And,
19 again, I want to thank you for allowing me to
20 testify out of turn here, given my schedule for
21 travel for today.

22 But, fortunately, with all the reports
23 we've had to analyze and the many workshops we
24 have participated in over the last two weeks, and
25 you Commissioners have sat through patiently over

1 at least the last two weeks, we haven't had a lot
2 of time to review the latest materials.

3 But based on a quick review of the staff
4 report entitled, preliminary reference case in
5 support of the 2005 natural gas market assessment,
6 we do have several comments to share with the
7 Commission.

8 The first is that WSPA strongly supports
9 the Commission's long-term policy goal. That goal
10 is described as quote, "to insure a reliable
11 supply of natural gas sufficient to meet
12 California's demand at reasonable and stable
13 prices and with acceptable environmental impacts
14 and market risk."

15 Secondly, we agree that the staff's
16 report's interpretation that the state's natural
17 gas policy goal makes reliability of supply the
18 top priority; followed by reasonable and stable
19 prices. And we support the conclusion that these
20 goals must be achieved in a manner consistent with
21 environmental and public health and safety
22 protection requirements.

23 Let me also take a moment to revisit a
24 few of WSPA's core beliefs and policy positions
25 related to the IEPR, to natural gas, and LNG. Our

1 core energy belief is that California government
2 must promote a balanced future energy base. One
3 that is reliable, cost effective, environmentally
4 attractive -- excuse me, economically attractive,
5 and environmentally responsible. This needs to be
6 done if we're to meet our state's future energy
7 supply/demand challenges.

8 For natural gas, WSPA encourages
9 expanded production of instate resources
10 consistent with maintaining environmental
11 protection. We also support additional natural
12 gas pipelines. Both intrastate as well as
13 interstate lines are needed to increase available
14 and cost effective supplies.

15 Another topic we have stressed before,
16 streamlined, environmentally sound permitting
17 procedures should be used to facilitate more
18 drilling of exploration wells. This should result
19 in more timely development of energy resources
20 that remain within state boundaries.

21 Natural gas prices have more than
22 doubled since 2001 in part because only 15 percent
23 of our needs are produced in California, and U.S.
24 supplies are not increasing fast enough.

25 At the same time, demand for natural gas

1 has been increasing primarily because the state's
2 new electricity plants are powered by natural gas.
3 And as you've heard, at least one sector of the
4 industrial complex, refining, among which some of
5 my members participate, has been producing at
6 record rates for the last several years just
7 trying to keep up with the demand for petroleum
8 products.

9 I think all that illustrates why
10 California may be at an energy cross-roads. To
11 avoid dramatically higher natural gas and
12 electricity prices in the future, we need to
13 increase natural gas supplies.

14 WSPA believes it is critical for
15 California to promote several specific policy
16 initiatives to accomplish this objective. These
17 include development of additional interstate
18 pipeline capacity from Canada, the southwest and
19 the Rocky Mountain region.

20 Operational flexibility to utilize
21 instate storage. Development of instate
22 production capacity. And development of
23 nontraditional supply sources, such as LNG.

24 Let me interject something here that
25 came up two days ago in one of your workshops on

1 climate change. I think there's even a possible
2 connection between sequestration of CO2, down-
3 holed, if you will, in production wells, for
4 enhanced oil recovery. That's what it's used for
5 in the production side of the business. And
6 resulting in more energy supplies being produced.

7 I think it's important that we collectively
8 pursue those types of possible opportunities.

9 Back to LNG. LNG provides an
10 opportunity for California to access supplies from
11 other countries and continents. And this may
12 result in downward pressure on Canadian and U.S.
13 gas prices.

14 WSPA applauds the Commission for your
15 initiatives in the area of promoting future LNG
16 use in California. We have previously recommended
17 designation of an existing state agency to
18 facilitate the siting of LNG projects, and to
19 clearly delineate an expedited regulatory process.
20 There is still a great need to promote careful
21 objective examination of all project proposals.
22 And to maintain the determination and will to
23 insure installation of enough capacity that meets
24 all appropriate safety and environmental
25 protection standards.

1 WSPA believes LNG is essential to
2 insuring a reliable supply of power to California
3 homes and businesses and to keeping electricity
4 prices low. This is especially true in California
5 where more than 40 percent of our electricity
6 generating capacity is fueled by natural gas.

7 Now I'd like to make some specific
8 comments and suggestions related to this most
9 recent Energy Commission report. The report
10 states California has adequate infrastructure to
11 insure reliable delivery of natural gas.

12 However, it's important to remember that
13 the existing infrastructure must be retained and
14 maintained in order for that to remain an accurate
15 statement. Also, I believe this doesn't include,
16 as yet, an adequate infrastructure for LNG
17 deliveries and further distribution as natural
18 gas.

19 To be really specific, on page 52 the
20 report poses the question: Does LNG offer enough
21 benefits to California to outweigh its potential
22 negative impacts, and should the state adopt a
23 policy recommending the direct import of LNG into
24 California?"

25 WSPA believes that this question has

1 somewhat of a negative tone, and we'd like to see
2 it revised to more clearly focus on the need for
3 new LNG facilities to serve California, and for
4 state government to take steps, specific steps to
5 insure that the necessary facilities become a
6 reality. A little bit different way of addressing
7 the issue.

8 Another observation is that the report
9 forecasts lower natural gas demand growth in
10 California than in the nation, as a whole. I
11 think the number was about .7 percent per year.

12 This forecast is similar in type and
13 direction to the .1 percent growth rate predicted
14 for gasoline demand. And as I remember, the
15 Commissioners questioned staff vigorously about
16 that prediction, that forecast, when you reviewed
17 the staff's reports on the petroleum
18 infrastructure and demand.

19 If California's population and economic
20 growth rates are closer to historic results than
21 to what I remember the staff's assumptions being
22 in the earlier reports, and presumably they are
23 the same for this report, the actual natural gas
24 demand could be significantly higher than
25 expected. In that case the need for additional

1 supplies of natural gas and LNG would be even
2 greater.

3 I think just that point makes it clear
4 that the demand growth forecast probably deserves
5 another look. And maybe even as the two
6 Commissioners suggested, for the last forecast
7 some independent observation to augment support,
8 counter the assumptions that are in the staff
9 report.

10 WSPA supports staff comments on the need
11 for consumers to invest in energy efficiency
12 measures to help produce their usage and costs.
13 Our industry has historically spent lots of time,
14 energy - not to pun - and money on measures to
15 reduce energy costs and that trend continues.

16 I think you saw Tuesday a chart that
17 showed still from API, a significant amount, over
18 40 percent of refinery operating costs that are
19 not raw material costs or energy costs. So, for
20 an industry as large as California's refining
21 industry there's a tremendous incentive to work in
22 whatever way we can cooperatively with you to
23 reduce energy use, and therefore demand. And we
24 urge other consumers to do the same.

25 We also agree that the state should

1 pursue additional supplies of natural gas by
2 supporting policy initiatives such as increasing
3 domestic natural gas production, developing
4 supplemental natural gas supplies and alternative
5 energy sources that will increase overall
6 supplies. And creating a priority for timely
7 infrastructure additions so supplies can continue
8 to be reliably delivered without causing localized
9 congestion.

10 In closing, I want to reiterate WSPA's
11 core energy supply belief. That is the key to
12 achieving California's long-term policy goal of
13 insuring a reliable supply of natural gas and
14 other energy is that the state government must
15 promote a balanced future energy base, reliable,
16 cost effective, economically attractive and
17 environmentally responsible.

18 Also want to leave you with the idea
19 that WSPA appreciates the continued efforts by the
20 Energy Commission and CPUC to work with all
21 stakeholders, the petroleum industry, utilities,
22 CARB, the Air Districts, community members and
23 environmental advocacy groups on resolving natural
24 gas quality issues.

25 We are working, in my opinion working

1 well collectively to come up with a win/win
2 solution that satisfies both energy and air
3 quality needs.

4 Again, I thank you for allowing me to
5 speak out of turn. And I would be happy to answer
6 any questions you might have.

7 COMMISSIONER BOYD: Thanks, Joe. I
8 believe you missed some of the morning
9 presentations, so you may not have been here when
10 we had quite a bit of a discussion about thermally
11 enhanced oil recovery and its demand for natural
12 gas.

13 The staff projection, which is
14 predicated on information they received from the
15 Division of Oil and Gas, shows a fairly
16 significant decline over time. And there were a
17 lot of questions from up here, from Commissioner
18 Geesman in particular, about that forecast.

19 And I did ask about how much input we
20 might have had from the producing industry, the
21 oil industry, the users of this.

22 And it just sounds to me like we, the
23 staff, could use some help from you in this area
24 to double check our staff's assumptions, and to
25 ascertain whether we both see eye-to-eye on this

1 decline. I don't think we programmed in yet CO2
2 injection to continue enhanced oil recovery. So,
3 I think we're still dependent upon, you know, gas-
4 fired boilers to produce steam to do that. So
5 that's one issue.

6 The other is you have been here long
7 enough to hear the last two presentations from the
8 two gas utilities about demand growth versus the
9 staff's. And you already see there's a difference
10 of opinion there with regard to -- I mean not a
11 big difference of opinion, but I think the
12 utilities don't see demand growing quite as much
13 as staff estimates contain at the present time.

14 But you make kind of an opposite
15 statement about maybe needing another third look
16 at, an outside look at demand growth forecast
17 needs, because apparently your folks see a greater
18 demand than either of us, the utilities so far,
19 and the staff are seeing.

20 So, there's another area that we could
21 use some, probably, reconciliation and some
22 consultation on the ideas and projections.

23 MR. SPARANO: Yeah, to be sure, our
24 industry, and me in particular, do not have any
25 special insight more than your staff or the

1 utilities.

2 The way I was coming at my observation
3 and suggestion is that some of the assumptions
4 used before that underlie energy use, forecasted
5 energy use in California all seem to be looking in
6 the same direction, lower population growth, lower
7 immigration rates, tend to suggest a economic
8 growth rate lower than before.

9 And based on the impacts on our industry
10 and the demand for products that's not going to go
11 away even if we devise a way to integrate
12 alternative fuels smoothly, seamlessly into the
13 supply chain for California. You still have a
14 huge demand pull. And I think even in your latest
15 projections, California's population continues to
16 grow. And energy use will continue to be
17 required.

18 And even the expectation that instate
19 supplies will be lower, and therefore perhaps
20 requiring less energy, that has to be made up from
21 somewhere. And we've talked extensively about the
22 influence of imports and infrastructure changes,
23 and the need to operate all that infrastructure
24 and cold ironing at the ports.

25 I see a lot of things, Commissioners,

1 that aren't particularly quantitative, but from a
2 qualitative assessment we wanted to share that
3 concern with you and ask that you consider having
4 a third view look at that. Now, if we're wrong,
5 we're wrong. But, I'd hate to be wrong and have
6 all of us looking for more supply with no time to
7 develop it.

8 PRESIDING MEMBER GEESMAN: I had one
9 other area to add to Jim's list. If your staff
10 would take a look at the assumptions that our
11 staff is using for growth in natural gas demand in
12 Baja. And we have derived our input assumptions,
13 as I understand it, entirely from the National
14 Petroleum Council.

15 But if you would simply take a look at
16 that and confirm that that's the best estimate
17 available for us to use I would appreciate it.

18 MR. SPARANO: Yes, sir, will do.

19 PRESIDING MEMBER GEESMAN: Thanks very
20 much.

21 MR. SPARANO: Thank you.

22 PRESIDING MEMBER GEESMAN: Jairam.

23 MR. GOPAL: All right. We will continue
24 now with -- this is not a fire drill, so please be
25 seated.

1 (Laughter.)

2 MR. GOPAL: We will continue with the
3 modeling, first that we have going on here
4 supporting the preliminary reference case. And at
5 this point I will call Leon Brathwaite to talk
6 about the modeling framework.

7 We talked about the demand earlier on.
8 Leon will address the modeling framework very
9 briefly. Then we talk about the supply and the
10 resource base assumptions. Follow that with the
11 infrastructure implications. And finally the
12 price issues.

13 And basically we will be talking about
14 how the model has been structured, what are the
15 input assumptions, and what are the results we are
16 looking at.

17 MR. MAUL: Commissioners, while they're
18 getting the slides ready, just for logistics here,
19 it's 11:45. We could complete this morning's
20 presentations on supply infrastructure and price
21 in probably the next half an hour to 45 minutes.
22 Or we could break now for lunch. It's your
23 choice.

24 PRESIDING MEMBER GEESMAN: Why don't we
25 complete this section and break at 12:30 or 12:45.

1 MR. MAUL: Okay. Thank you.

2 MR. BRATHWAITE: Good morning,
3 Commissioners, members of the audience. My name
4 is Leon Brathwaite. I work in the natural gas
5 office. I run the model that we are using for the
6 natural gas portion of the IEPR report.

7 What I will do is that I will give a
8 brief overview of the model that we are using. I
9 will not get into some of the very mundane
10 details. I will just lay out a broad structure of
11 how the model looks and its functions and some of
12 the inputs that are required.

13 Okay. No, we don't need that. Am I
14 going the wrong way? Yeah, I'm going the wrong
15 way, I'm sorry, I apologize for that. I was going
16 the wrong way.

17 Okay, the model's a long-term market
18 analysis. And the forecast horizon that we are
19 forecasting on is 2006 to 2016. The model,
20 itself, is a 45-year time period, but we're only
21 forecasting on that ten-year period.

22 It is an annual average model. We do
23 not look at the short-term changes that we see in
24 the marketplace, as for instance as we see right
25 now, prices are running pretty high compared to

1 historic averages. But we look at annual averages
2 throughout the 45-year period. Again, still
3 focusing only on that ten-year period that are in
4 play right at this point in time.

5 In previous forecasts what we did was
6 that we had a model that we did things in five-
7 year increments. We are now restructured on a
8 model that now we can do things annually. We have
9 annual from 2001 all the way to 2017, I believe.
10 So we can look at things in a little more detail
11 than previous.

12 As I said, this analysis does not look
13 at the short-term market movements. We are more
14 interested in long-term behavior. On the next
15 phase of our work we will be looking at some of
16 the short-term issues that are related to the
17 natural gas market.

18 Many of the assumptions and inputs in
19 the model have been discussed in several workshops
20 and meetings with many of the stakeholders.

21 Okay, the model that we're using is the
22 North American regional gas model. It's been in
23 use here in the Commission since 1989. Our first
24 version of the model used a DOS-based version.

25 We recently converted to a Windows-based

1 version but is known as a market buildup platform.
2 And that has given us quite a lot of flexibility
3 to do things. It's onscreen, it's a very nice
4 interface. I have to thank the model developers
5 for that.

6 The model is a equilibrium model in that
7 it balances supply and demand of each node and
8 each time point in the model within the framework.
9 And it's an iterative solution. It goes through
10 several iterations to come to convergence. It may
11 be 100,000, 200,000 iterations, whatever is
12 necessary to get some acceptable error level
13 within the model.

14 Also we are focused on California and the
15 western states. But we really do look at the
16 entire North American continent; that is Canada,
17 United States and Mexico. Even though in Mexico
18 we do not have very much detail. And that is
19 something that we probably will have to work on
20 and develop a little more. But we will be looking
21 at that in the future.

22 Now, we have a rule about new projects,
23 that's for pipelines and say like for LNG
24 facilities, in that they must be permitted and
25 under construction before we include them in the

1 model. Now, there are a couple of exceptions to
2 that which I'll talk about as I go along in this
3 presentation.

4 Okay, sources of information. We have
5 had several sources of information and they have
6 been discussed. The Petroleum Council was
7 mentioned this morning. They have provided a lot
8 of the supply data that we use. We have
9 (inaudible) demand information. We also have
10 transportation information within the model for
11 the pipelines and the pipeline corridors. That is
12 also in the model. Some of that information came
13 from Ben Schlesinger Associates.

14 So we feel very confident about the data
15 inputs. Obviously, there are things that we still
16 have to work on, but those are ongoing processes
17 and investigations.

18 Okay, assumptions fall into four main
19 categories. We have supply, that is the cost and
20 resource availability; demand, which we had a lot
21 of discussion about that. And we have demand
22 divided up into several categories. We have
23 residential, commercial, industrial; and
24 industrial is broken up into two sectors. And we
25 also have the power generation sector.

1 We have the infrastructure, which is the
2 pipeline and the pipeline corridors. And when I
3 use the word pipeline corridor what I'm talking
4 about is two or more pipelines that run in the
5 same direction. In our model, even though
6 physically they may be two separate pipelines, in
7 our model we represent it as one. A good example
8 of that may be El Paso North and Transwestern,
9 which is represented as one pipeline corridor
10 within our model, even though it's physically two
11 different pipelines.

12 And the other, we have also some other
13 factors like oil prices and financial parameters,
14 such as (inaudible) taxes or (inaudible) are also
15 included, but those are not big issues within the
16 model.

17 Okay, now as I said, we have the entire
18 North American continent modeled. And we have
19 broken it down by the countries. We have Canada,
20 United States and Mexico. Then we have further,
21 do some further subdivision by breaking it up into
22 regions. And then taking it even further and
23 going into subregions where we take the entire
24 continent and break it up into these small units
25 that we can manage a little better, rather than

1 looking at one big huge humongous mass which we
2 wouldn't know what to do with anyway.

3 So, within each of the subregions that
4 we have, we have activity nodes. And those
5 activity nodes represent demand, and we spoke
6 about that. It represents supply, and I'll show
7 you an example of that shortly. It represents
8 transportation, which is the pipeline and the
9 pipeline corridors.

10 And we also have processing and
11 conclusions. For instance, it might be like a
12 gathering at a wellhead, that is represented. Or
13 maybe an LNG facility that is used for
14 regasification. That is also represented within
15 the model.

16 Okay, so the North American regional gas
17 model is a generalized (inaudible) model, and it
18 calculates market clearing prices and quantities.
19 Now, I want to be clear about it here when I use
20 the word market clearing prices. I am not talking
21 about a short-term daily spot prices that we see
22 in The Wall Street Journal every day. What we are
23 talking about here is annual averages, okay.
24 Annual averages, okay. We are not talking about
25 the short-term ups and downs that we see in The

1 Wall Street Journal.

2 The modifying prices and floors that
3 give us simultaneous equilibrium in all time
4 periods, in all subregions within the model. So
5 in order for us to have a converged case,
6 something that we can say we accept as a good run,
7 we must have this simultaneous equilibrium in all
8 time periods. And we have like 26 or 27 time
9 periods within the model. And we must have it in
10 all subregions. And I think we have about more
11 than 80 subregions within our model.

12 Now, this is a representation of a
13 supply region or supply subregion, if you wish.
14 This particular one came out of Montana. But we
15 have many of these within the model. Now, each of
16 those green hexagons you see there represent
17 resources within a region.

18 Now, those resources are represented by
19 supply cost goods. And what I'm talking about are
20 those price quantities, because that will tell you
21 how much could be available at any point in time
22 at what cost. And those supply cost curves are
23 probably the single most important thing that is
24 contained within the model.

25 And we have, I believe, about 200 supply

1 cost curves represented in the model, all over the
2 North American continent. We have them in Mexico
3 for the first time. We didn't have that
4 previously, but for the first time we have them in
5 Mexico now. We have all over the United States,
6 and all over Canada. As you know, Canada is a
7 major supplier of natural gas to California.

8 PRESIDING MEMBER GEESMAN: Now you
9 earlier said that infrastructure to be included
10 needed to be both permitted and under
11 construction. Have you applied a similar
12 constraint here on supplies?

13 MR. BRATHWAITE: No, not necessarily.
14 All these representations we have in the model, we
15 have wells that are already in production. It is
16 represented in the model. We have reserves that
17 maybe that is already connected, but not yet
18 producing; that is also in the model.

19 But we also have categories known as
20 yet-to-find, which is things that we believe will
21 be found at some point in time in the future.
22 But, of course, those things will be available at
23 a higher cost.

24 Now, so on the infrastructure side, that
25 rule applies. But here we do it a little bit

1 different statistical analysis and determine some
2 of the resources that we put into the model.

3 PRESIDING MEMBER GEESMAN: Okay.

4 MR. BRATHWAITE: Next slide. Now, this
5 is an example of the demand side. And Mark spoke
6 a lot about this this morning. And Lynn also
7 chimed in on some of the issues here.

8 Now, the blue areas -- let me use our
9 thing here -- these -- is it showing? The blue
10 one. Those blue, are demand nodes. And these
11 are, well, you know, they look like tombstones.
12 It is where natural gas go to die, to be used up.

13 (Laughter.)

14 MR. BRATHWAITE: That was a joke, sorry.

15 (Laughter.)

16 MR. BRATHWAITE: Okay. So the blue one,
17 those are the elastic nodes. And this was a
18 recent incorporation into our model, in the sense
19 that previously all of our demand nodes were all
20 inelastic just like the power generation one that
21 we see here. And this one here, if I can -- yeah,
22 this one here is the power generation. And that
23 is inelastic.

24 But the elasticity really is handled
25 outside the model in the sense that we go through

1 iterations to look at how price affects the demand
2 on those nodes that are inelastic within the
3 model. The other nodes, the dark blue ones, the
4 elasticity, the price effects are internal to the
5 model. The red triangles are really all
6 transportation nodes. Those are pipelines or
7 pipeline corridors that are included in our model.

8 So this is how the model is set up. We
9 have supply connected by the triangles, which are
10 the transportation. And the transportation sends
11 resources up into the demand nodes; where the
12 demand ultimately is used up, and died, as we have
13 said.

14 PRESIDING MEMBER GEESMAN: What are the
15 green dots?

16 MR. BRATHWAITE: The green dots are
17 allocations. And that's a good question, thank
18 you for asking it.

19 The green dots are the allocation. This
20 is where all calculations occur within the model.
21 All calculations. This is where it determines
22 market shares; all the supply information. This
23 is where all the balancing of supply and demand
24 goes on, at those locations. It's probably the
25 most important thing within the model in terms of

1 its calculation efforts.

2 Okay, I just want to talk about some
3 broad assumptions that are within the model. And
4 I think Mark spoke about the GDP, U.S. GDP. It's
5 about 3 percent. Canadian GDP is about 2.5
6 percent.

7 PRESIDING MEMBER GEESMAN: And that
8 comes from EIA's assumptions?

9 MR. BRATHWAITE: That's EIA, isn't it?
10 Yes. It is EIA.

11 MR. DiGIOVANNA: The --

12 PRESIDING MEMBER GEESMAN: Got to come
13 up to the microphone, Mark.

14 MR. DiGIOVANNA: All right, the U.S. GDP
15 was taken from the Annual Energy Outlook 2005. We
16 just used the same assumptions that they did,
17 since we were using their power gen forecast.

18 For the Canadian assumptions, we
19 actually went through staff's Canada -- statistics
20 of Canada and purchased both their historical GDP,
21 and I believe a projection on that. This was
22 actually something that we got the data and turned
23 it over to Ken Medlock, and he actually came up
24 with that assumption based on the data that we had
25 sent him.

1 PRESIDING MEMBER GEESMAN: And for U.S.
2 GDP, how hard would it be to run economy.com to be
3 consistent with the input for Lynn's California
4 economic growth assumptions?

5 MR. DiGIOVANNA: As long as it takes to
6 type it.

7 PRESIDING MEMBER GEESMAN: Okay.

8 MR. DiGIOVANNA: Basically, I mean, the
9 reason we picked the one that we did was just to
10 stay consistent with the power generation on the
11 east coast. But it probably wouldn't make a huge
12 difference as far as the inconsistency that it
13 creates.

14 PRESIDING MEMBER GEESMAN: Okay.

15 MR. BRATHWAITE: Thank you, Mark. And
16 as I will continue. Now, the gas demand grew from
17 generation in the WECC is at 2.5 percent per year.
18 Residential, commercial, industrial, they are
19 elastic representations, as I spoke about
20 previously. Obviously the power generation
21 internal to the model is inelastic, but the
22 elasticity is handled outside the model.

23 The gas resource base came from NPC.
24 You know NPC had done quite a lot of work, and
25 they published a report in 2003. We are using

1 most of the information on the supply side in the
2 model. We will be taking a look at that even
3 closer to see if there are adjustments that can be
4 made to some of that data. So that is an ongoing
5 investigation.

6 The gas supply curves which are the cost
7 curves which I spoke about a short while ago, now
8 these curves, as I said, are probably the single
9 most important item within the model. And we have
10 to be very careful about their use and the data
11 that we do input into the model for these curves.
12 And we will be -- again, these are things that we
13 will be looking at as we continue this process.

14 A lot of the data, again, came from NPC
15 and from USGS.

16 PRESIDING MEMBER GEESMAN: That's the
17 most current information available?

18 MR. BRATHWAITE: Yes, it is, sir.

19 PRESIDING MEMBER GEESMAN: And prior to
20 that 2003 update, that data hadn't really been
21 updated for about ten years, had it?

22 MR. BRATHWAITE: Something like that, I
23 believe. I think the last one was 1994, if I'm
24 not mistaken, wasn't it? Yeah.

25 MR. GOPAL: It was a 1995 USGS estimate

1 that was used right in the beginning of the '98
2 analysis. Later on we had just done some regional
3 updates of Gulf and Rocky Mountains. But it was
4 not a total update.

5 PRESIDING MEMBER GEESMAN: But it sounds
6 like you've been successful in gaining a more
7 current set of the input assumptions this time
8 around.

9 MR. GOPAL: That is correct.

10 MR. BRATHWAITE: Yes.

11 PRESIDING MEMBER GEESMAN: Thank you.

12 MR. BRATHWAITE: Yes, most definitely,
13 yes.

14 Now, this, I told you about our rule in
15 terms of an infrastructure, about putting things
16 into the model, that must be permitted and under
17 construction. And this is one of the places where
18 we have kind of broken that rule because of the
19 importance of these two infrastructure facilities.

20 It's the Alaska gas pipeline which we
21 expect to be in service in 2015. Now, there might
22 be more current information on that. That could
23 be an adjustment that we can make within the
24 model, if necessary.

25 The MacKenzie Valley pipeline, which we

1 expect to be in service in 2010. Again, if there
2 is more current information on that we could also
3 adjust that to be more realistic.

4 Again, this is where we have kind of
5 broken our rule in terms of things have to be
6 permitted and be under construction before we
7 input it into the model.

8 The crude oil price that we use, even
9 though the crude oil price is not directly
10 inputted into the model, but Mark does use it in
11 terms of some of his demand information, that came
12 from EIA 2005 annual energy outlook. And they use
13 the high-A case.

14 We also have LNG identified within the
15 model. We have a complete structure for LNG in
16 terms of the source of the LNG, in terms of the
17 transportation of it, in terms of the
18 regasification facilities that we expect to be
19 constructed.

20 In the model we have the four existing
21 facilities. We also have four new facilities on
22 the east coast and in the Gulf of Mexico. We also
23 have one in Baja which is probably one that is
24 closer to construction than any of the others.
25 And we also have one in east Mexico which, I

1 believe, is the Alta Mira facility.

2 PRESIDING MEMBER GEESMAN: Now you've
3 got that identified as LNG through 2010.

4 MR. BRATHWAITE: Yes, those are the
5 facilities we expect to be in operation.

6 PRESIDING MEMBER GEESMAN: So these
7 would all be online and operating --

8 MR. BRATHWAITE: Before 2010.

9 PRESIDING MEMBER GEESMAN: -- before
10 2010.

11 MR. BRATHWAITE: Yes.

12 PRESIDING MEMBER GEESMAN: And that
13 would also include expansion at the existing four
14 U.S. terminals?

15 MR. BRATHWAITE: Yes.

16 PRESIDING MEMBER GEESMAN: And do you
17 make any additional assumptions about LNG post
18 2010?

19 MR. BRATHWAITE: No, we don't. But one
20 of the things that's under discussion in the
21 office right now is whether we shall -- we have
22 capped all of the energy facilities as its
23 capacity, in that it does not show above capacity.
24 But the model allows us the flexibility whereby we
25 can release that cap and allow the facility to

1 expand as much as necessary.

2 Now, the expansion may be an expansion
3 for that particular facility, or a new facility,
4 okay. But in the model it may be just we would
5 just represent it as the expansion of whatever
6 facility that we put in.

7 So, what is under discussion right now
8 within the office is whether we should release
9 those caps and allow the model to expand as much
10 as it's economically necessary. And that will
11 give us some idea as to what will happen after
12 2010.

13 PRESIDING MEMBER GEESMAN: And you said
14 that you have set the cap at capacity.

15 MR. BRATHWAITE: Of the facility, yes.

16 PRESIDING MEMBER GEESMAN: As currently
17 proposed.

18 MR. BRATHWAITE: Yes.

19 PRESIDING MEMBER GEESMAN: So, of a
20 particular facility you have not assumed any
21 expansion of that facility beyond its currently
22 proposed capacity?

23 MR. BRATHWAITE: That is correct, yes.

24 PRESIDING MEMBER GEESMAN: Okay.

25 MR. BRATHWAITE: And that takes me to

1 the end of my presentation. And I will happily
2 answer any questions that anyone may have.

3 PRESIDING MEMBER GEESMAN: Thanks, Leon.

4 MR. BRATHWAITE: Thank you very much,
5 Commissioners.

6 MR. GOPAL: We'll next have Mike Purcell
7 to talk about the supply, the resource base and
8 implications of what we have seen in the
9 preliminary reference case.

10 MR. PURCELL: Good morning, everyone.
11 Thanks for coming and putting up with the fire
12 drill. I guess everybody made it back, which is
13 good.

14 I'm going to talk about supply today.
15 And the supply assessment that was done by the
16 NPC; the projected natural gas supplies available
17 to the United States during the modeling period;
18 the changes in North American production that
19 we're seeing; projected natural gas supplies to
20 California; and the issue of natural gas quality,
21 which we've, you know, have been really involved
22 with now with our working group with us and CPUC
23 to try to get some standard worked out before LNG
24 is introduced into the state.

25 The data sources, as Leon mentioned, you

1 know, we used a lot of the stuff from the National
2 Petroleum Council, the United States Geological
3 Survey, the Minerals Management Service, which was
4 part of the USGS, but deals primarily with
5 offshore reserves. We also worked with the
6 Canadian Gas Potential Committee, IHS Energy
7 Group.

8 There was a lot of industry input into
9 the reserve studies, and also working with local
10 producers. And I think, you know, one of the
11 strengths of the NPC study was that they went out
12 to the various producing areas and had workshops
13 with the local producers. And actually, you know,
14 vetted the information from the USGS, and had guys
15 that were really drilling, really working in the
16 various basins, go, you know, what do you think of
17 these numbers.

18 And so people with direct hands on
19 experience in those areas were able to, you know,
20 put some of their input into it. And I think what
21 NPC did is they, from the difference between the
22 U. S. Geological Survey and the NPC, the NPC was a
23 lot more conservative and cut down a lot of the
24 reserve estimates that USGS had already published
25 in their previous, I guess the 1995 assessment.

1 So the NPC is more conservative than the USGS
2 estimates.

3 PRESIDING MEMBER GEESMAN: And why is
4 that a good thing?

5 MR. PURCELL: Because I think that being
6 more conservative constrains things probably to
7 the way, you know, that I feel what is realistic,
8 and what could -- where it's really going to be
9 able to be pulled out of the ground. And I think
10 some of the estimates in the USGS are overly
11 optimistic on what would really happen.

12 PRESIDING MEMBER GEESMAN: And this
13 effort was done, I can't recall if it was 2003 or
14 2004, by NPC?

15 MR. PURCELL: 2003 by NPC.

16 PRESIDING MEMBER GEESMAN: At a time
17 when prices were in the \$4 range?

18 MR. PURCELL: Around there. They were a
19 little higher than that, I think, then, so --

20 PRESIDING MEMBER GEESMAN: Okay, but
21 significantly lower than they are today.

22 MR. PURCELL: Yes.

23 PRESIDING MEMBER GEESMAN: Do you think
24 that if you did the same evaluation -- or if NPC
25 did the same evaluation today they might be less

1 conservative?

2 MR. PURCELL: Possibly. But that would
3 be how the -- you know, the cost curves would have
4 to be adjusted --

5 PRESIDING MEMBER GEESMAN: Sure.

6 MR. PURCELL: -- to the new prices. And
7 there would probably, possibly add some reserve to
8 that by using a higher price. But that would be,
9 you know, kind of a revision of the cost curves.
10 And that's something right now that we're looking
11 at, you know, to see where we think that maybe
12 some of these cost curves should be changed. So
13 that's something that we're going to be going back
14 through.

15 PRESIDING MEMBER GEESMAN: I just recall
16 back when the United States still regulated the
17 price of natural gas, the concern that we were
18 running out of gas and once we deregulated the
19 price of natural gas, there certainly seemed to be
20 an awful lot of gas around.

21 MR. PURCELL: Um-hum.

22 PRESIDING MEMBER GEESMAN: Probably 15
23 years or so --

24 MR. PURCELL: Right. And I think, you
25 know, that's very true. But I think the way we're

1 seeing the development in the market now, I -- you
2 know, we've got to be getting close to the balance
3 of supply and demand now. I think that's why
4 prices are so high, because we can't just go and
5 add a huge amount of supply by drilling in the
6 lower 48 or the traditional areas.

7 And I think, you know, that's needs to -
8 - we'll talk about it more later, that you know,
9 we do need to augment the supply, probably from
10 LNG, from gas from Canada, from MacKenzie and
11 Alaska.

12 PRESIDING MEMBER GEESMAN: Yeah, I
13 think, and we'll get into this in the afternoon,
14 but I think that the Commission largely crossed
15 that threshold in its 2003 report. So I guess I'm
16 less focused on what those bottomline implications
17 are than trying to go back and reassess whether
18 all of our top line inputs are reasonably sound.

19 And I tend to attach a fair long-term
20 significance to price influences. If the price of
21 natural gas is materially higher than it was when
22 NPC conducted its assessment, and I place a great
23 deal of strength on the NPC assessments, certainly
24 in comparison to the earlier USGS efforts.

25 But if prices have changed materially

1 since then it's the sort of thing that raises a
2 question in my mind as to how dry are all those
3 existing holes; how much enhanced recovery
4 potentially might be available at higher prices
5 from the lower 48 going forward.

6 MR. PURCELL: You know, we're seeing
7 right now, you know, drilling's at a very high
8 level, you know, as high as it was back in '82 or
9 in the early '80s. And we're just kind of staying
10 even. And I'll talk about that a little more, but
11 even with a lot more drilling and better
12 technology, we, you know, aren't seeing a dramatic
13 increase in supply.

14 PRESIDING MEMBER GEESMAN: Well, that's
15 what I wanted you to get into and --

16 MR. PURCELL: Yeah, and that's coming
17 up.

18 PRESIDING MEMBER GEESMAN: Okay.

19 MR. GOPAL: Well, basically I think even
20 with discussions with NPC folks, one of the things
21 that is very clear is the uncertainty in what
22 these future resources can bring to us.

23 And one of the things that we certainly
24 will be doing is to look at some sensitivities to
25 see what happens if either there is not as much

1 resources, or it's going to cost even more to pull
2 them out of the ground.

3 MR. PURCELL: Here's the next slide.
4 Just shows the gas supplies available in North
5 America during the model period that were produced
6 by our model. And I think you can see that the
7 lower 48 production is rising, which is the blue,
8 you know, fairly significantly during that time
9 period.

10 But these increases are going to come
11 primarily, you know, from the deep water Gulf of
12 Mexico and the Rocky Mountains is where the most
13 potential is. And a lot of the areas in the Rocky
14 Mountains the production increases are going to be
15 from nonconventional sources such as coal bed
16 methane and tight gas formations.

17 The assessment right now assumes that
18 MacKenzie comes in at 2012 and Alaska will start
19 at 2013. And you can see it -- do we have a
20 pointer -- on the chart.

21 PRESIDING MEMBER GEESMAN: I can see
22 Alaska, but I can't see MacKenzie.

23 MR. PURCELL: Well, MacKenzie, this is
24 all of Canada in here. So MacKenzie doesn't
25 really, you know, it's kind of compensating, I

1 think, for other declines in Canada as it comes
2 in.

3 MR. TOMASHEFSKY: Mike, getting back to
4 an earlier comment that Mark made earlier about
5 the end use demand assumptions.

6 MR. PURCELL: I don't know anything
7 about demand.

8 MR. TOMASHEFSKY: Well, that's why
9 Mark's pretty close to the podium. How is the
10 impact of that pipeline coming on impacting what
11 our assumptions are with respect to total Alaska
12 demand and Asian demand? And also as LNG comes
13 into the model results, how does that impact the
14 Asian demand there?

15 Because before we just kind of sent
16 Alaska gas off, we really didn't care about it,
17 because it wasn't really connected to the model.
18 But, as you bring these things in, you're now
19 connecting Alaska and its pool against the model
20 results.

21 MR. GOPAL: The Asian demand is still
22 fixed amount that goes right off Alaskan supplies.
23 There is so much gas in Alaska that whatever is
24 being produced would come to the U.S. and the
25 Asian demand, still Alaskan resources are larger

1 than the total demand that's in these two regions.

2 MR. TOMASHEFSKY: Okay, so there's no --

3 MR. GOPAL: It really does not impact it
4 directly, no. The fact that you're going to be
5 pulling a lot more gas out, of course, raises
6 Alaskan in price over time, but it's not so
7 significant that you're going to be looking at
8 Alaskan resources getting exhausted at this time.

9 MR. TOMASHEFSKY: Okay.

10 MR. PURCELL: I'll go through later on a
11 little bit on how much gas is in Alaska. You
12 know, as Jairam said, there's a lot, and, you
13 know, if it is developed and there's a huge
14 resource there.

15 MR. MAUL: Scott, I think also the
16 question of the connection between Asia and
17 Alaskan gas gets to how Alaskan gas is eventually
18 developed and delivered to North America.

19 If it's overland pipeline, as the big
20 producers are currently proposing, then there is
21 no connection between Asia and Alaska because the
22 pipeline systems are actually separate. Current
23 gas out of Alaska is going the LNG out of the
24 Cooke Inlet into Japan right now.

25 If, however, the alternative proposal,

1 which is being considered inside the State of
2 Alaska, involves a spur line off that main line
3 coming down that either goes to Valdez in the form
4 of LNG, or additionally going to southcentral
5 Alaska to feed Anchorage and the Cooke Inlet and
6 the industries down there, then you would connect
7 the two sources and the main would become
8 connected. So, it's still an open question of
9 which infrastructure pathway the State of Alaska
10 is going to choose.

11 MR. TOMASHEFSKY: I just would be
12 curious how the interaction between LNG comes to
13 the west coast, how does that then compete with
14 the LNG coming to the west coast. Do you get into
15 a competition for that supply, and does Alaska
16 then play a role coming into California or other
17 parts?

18 MR. MAUL: That's the active debate up
19 right now in the Governor's Office in the State of
20 Alaska, the Legislature and the producers.

21 MR. PURCELL: Just to put this in
22 perspective right now, at 2006 the model's
23 projecting, it's 80,000 million cubic feet a day,
24 which is about 27 tcf a year. And during the
25 modeling period then to 2016 we're projecting that

1 it's going to rise up to 34 tcf.

2 However, you know, this is, I think, a
3 real telling slide as far as what kind of drilling
4 activity we're going to need in the United States,
5 especially the lower 48, in order to maintain that
6 production that we showed in the blue that was
7 steadily rising. This slide shows the rates of
8 decline of wells in aggregate that were drilled in
9 1990, 1991, 1992, you know, out through 2002.

10 And what you can see there is that the
11 rate of decline, you know, is increasing as we
12 move forward in time. And there's several factors
13 and there's disagreement on, you know, what that
14 means. But in my personal opinion, it's, you
15 know, in part, due to a shrinking resource. And
16 that we're drilling smaller and smaller things.
17 We're not drilling into a giant accumulation that
18 will decline in a longer term fashion.

19 But, on the other hand, then there's the
20 issue of a lot of the wells these days are now
21 being fractured, you know, to enhance their
22 production. And when that fracturing occurs you
23 can pull the gas out a lot faster. So you're
24 sucking out, you know, the same volume but in a
25 much shorter time.

1 And so there's a lot of factors that are
2 in this situation that make it a little bit
3 ambiguous to what the real reason is. But I
4 think, you know, there's several different things.

5 You know, another issue is with the new
6 three-dimensional seismic that everybody's using,
7 you can look for a lot smaller accumulations.
8 Just for example, in the Sacramento Valley, back
9 in the 1980s pretty much the minimum size well
10 that would be drilled was a billion cubic feet.
11 And that was pretty much, you could make maybe 3
12 million bucks at those gas prices. And, you know,
13 that was good profit on putting \$400,000 or
14 \$500,000 out, you know, to make that money.

15 Whereas now with gas prices the way they
16 are a billion cubic feet is worth more like \$15 or
17 \$16 million. And so there is prospects on the
18 street now being sold in this valley for people to
19 drill for a quarter of a bcf.

20 So, just inherently there that's a
21 smaller well, no matter what's going to happen.
22 And you're going to get it, you know, there's less
23 there that's going to come out, and it's going to
24 come out quicker because there's not as much. So,
25 you know, that's another part of this equation.

1 PRESIDING MEMBER GEESMAN: Where does
2 this data come from, Mike? Explain a little bit
3 about your source and who IHS Energy Group is and
4 what it purports to cover.

5 MR. PURCELL: You know, IHS was used by
6 the NPC.

7 PRESIDING MEMBER GEESMAN: Okay.

8 MR. PURCELL: And this data is an
9 aggregation of all the wells, gas wells that were
10 drilled in the United States.

11 PRESIDING MEMBER GEESMAN: So it covers
12 both onshore and offshore?

13 MR. PURCELL: I believe it's just
14 onshore.

15 PRESIDING MEMBER GEESMAN: Okay.\

16 MR. PURCELL: You know, offshore could
17 be a bigger difference, especially with the
18 expansion in the drilling in the deep Gulf of
19 Mexico where, you know, there's been some big gas
20 holes found.

21 PRESIDING MEMBER GEESMAN: Okay.

22 MR. PURCELL: The next slide just shows,
23 hopefully you can read that. It shows the various
24 basins that supply gas to California. You know,
25 you have the western Canadian sedimentary basin,

1 which this shouldn't really be the Saskatchewan
2 Basin, it's really all one big basin. But
3 Williston, the various basins in the Rocky
4 Mountains.

5 San Juan, which is a real important
6 source for California. The Permian, a little bit
7 from the Anadarko, and then the Los Angeles Basin
8 and offshore southern California, San Joaquin
9 Basin, Sacramento Valley, and the Mist gas field
10 is the only production in the Pacific Northwest.

11 And you can see there are various
12 reserve numbers here. The western Canadian
13 sedimentary basin has the highest proven in
14 potential reserves in onshore U.S. and Canada
15 proper. And followed by the Rocky Mountains.

16 The Rocky Mountains have the most
17 potential onshore in the United States. But, you
18 know, there's issues there with land access, and
19 you know, about half of that resource is in
20 environmentally sensitive areas that, you know,
21 may or may not be allowed to be drilled for.

22 And that's excluding like national parks
23 or monuments. But these are just areas where
24 there's various migratory animals, elk and
25 everything, where they can only drill maybe two

1 months, three months out of the year. And that
2 makes it hard for producers to get in there in a
3 timely manner and actually drill wells.

4 MR. TOMASHEFSKY: Mike, is that factored
5 into the analysis that goes into the model?

6 MR. PURCELL: Yes.

7 MR. TOMASHEFSKY: Okay.

8 MR. PURCELL: Yeah, because we left the
9 off-limit parts out of the model. And the other
10 big elephant out there is offshore, you know, the
11 western United States. There's probably 21
12 trillion cubic feet of reserves in offshore. And,
13 you know, that gas is just sitting there not being
14 explored for, or gone after because of the
15 political climate, and certain opposition in
16 certain camps.

17 The other one that we don't show on here
18 because it doesn't really, you know, gas doesn't
19 come up that much from there, but Mexico has, you
20 know, a fair amount of reserves, and more reserves
21 are being added there now on the east side of
22 Mexico, along the Gulf; down in Veracruz and some
23 of those areas there's some big discoveries that
24 have been made in the last couple years. And
25 they're finding more and more. But right now

1 they're projecting that Mexico has about 40
2 trillion feet of proven reserves, and 48 more tcf
3 of reserve potential.

4 The next slide just shows the supplies
5 that are coming into California currently. And
6 that's why we purposely left this slide before the
7 modeling period so there's some real data in here.
8 You know, it starts at 2001 and you can see the
9 yellow is gas coming in at El Paso, mostly from
10 the Permian Basin.

11 The dark blue is El Paso North, which is
12 coming from the San Juan. The Kern River, which
13 is that, I don't know, blue or green, is coming
14 from the Rocky Mountains. And the TGC, which
15 comes in later, is from Mexico. But that, I
16 think, is from the LNG, you know, coming in.

17 And the other interesting thing to look
18 at this, is that we're able -- it's not so much
19 that the Permian gas in here is increasing
20 production, but what the model is telling us is
21 that the introduction of LNG on the Gulf Coast is
22 going to make more Permian gas available because
23 it will displace it westward towards us. So
24 that's why there's an increase in that portion of
25 the production.

1 The last thing I wanted to talk about is
2 just what's been going on with natural gas
3 quality, which is becoming, you know, it's a very
4 big issue right now. And a lot of people in the
5 audience we've been dealing with at various times
6 on our natural gas quality committee.

7 The issue is that natural gas, you know,
8 has a lot of variability. We've got gas coming
9 from interstate pipelines; we've got gas in
10 southern California; we have gas in northern
11 California; and then we have potential LNG gas
12 imports coming in.

13 And I think everybody's pretty familiar
14 that, you know, the interstate pipelines are about
15 1000 Btu, which is British thermal unit, which is
16 pretty much the standard measure of the heat
17 content of the gas.

18 And in southern California there's
19 issues, and Joe -- is he still here -- Sparano,
20 you know, mentioned earlier, you know, that the
21 issue that we've been dealing with a lot is how to
22 get some of the hot gas that's in southern
23 California, which is higher Btu gas, into the
24 pipeline, and being able to be used.

25 In northern California we have other

1 issues of gas that's only, you know, 400 or less
2 Btu that has to be gotten into the system. So,
3 there's blending going on. There's, you know,
4 treatment. But we really need to, with liquified
5 natural gas coming in, which, you know,
6 potentially has Btu contents of 1150, you know,
7 there's got to be a standard made. And that's,
8 you know, what we're working towards, to try to
9 make a standard that will work for all the
10 appliances and all the end users in the state.

11 So, we're intimately involved in that.
12 And actually it's been pretty positive lately that
13 we're heading to some resolution in that arena.

14 And I think that concludes my
15 presentation. If anybody has any questions?

16 PRESIDING MEMBER GEESMAN: Todd Peterson
17 from SMUD, did you have a question?

18 MR. PETERSON: I'm here, I --

19 PRESIDING MEMBER GEESMAN: Why don't you
20 come up to the microphone, Todd.

21 MR. PETERSON: This goes back to --
22 well, first of all, --

23 PRESIDING MEMBER GEESMAN: You need to
24 introduce yourself.

25 MR. PETERSON: -- Todd Peterson with

1 SMUD. This goes back -- on the handout, page 6,
2 this was back to Leon Brathwaite's preliminary
3 reference case assumptions.

4 I was curious to understand what were
5 the criteria behind choosing the online dates
6 capacities for the A&S gas pipeline, MacKenzie
7 Valley pipeline, and then also on LNG where the
8 LNG facilities would land, say the Gulf of Mexico,
9 east coast, Baja and east Mexico.

10 MR. BRATHWAITE: All right, how many
11 questions you asking here, now?

12 (Laughter.)

13 MR. BRATHWAITE: All right, now what --

14 MR. PETERSON: I'm really trying to
15 understand the criteria --

16 MR. BRATHWAITE: Where the pipelines --

17 MR. PETERSON: Yeah, behind the
18 assumptions.

19 MR. BRATHWAITE: -- for the A&S, that's
20 based on published information. However, there
21 have been some more dates on that, and we maybe
22 make some adjustments to that in the model.

23 So the A&S and the MacKenzie, those are
24 the dates that are presently in the preliminary
25 reference case in terms of the online, when they

1 become -- when they would come online. We may be
2 changing that based on more current information.

3 MR. PETERSON: All right. And then the
4 LNG facilities through 2010, is that also based on
5 published data?

6 MR. BRATHWAITE: Yes.

7 MR. PETERSON: All right.

8 MR. BRATHWAITE: And, well, also again
9 if there is more current information on that, we
10 will be making adjustments before we finalize the
11 basecase.

12 COMMISSIONER BOYD: And if one was
13 making a list of unknowns, uncertainties,
14 potential variables, weak assumptions, you just
15 touched them all.

16 (Laughter.)

17 COMMISSIONER BOYD: Of, you know, the
18 difficulty of seeing the future.

19 MR. BRATHWAITE: Indeed.

20 MR. PETERSON: Thank you.

21 MR. BRATHWAITE: Okay, thank you, Todd.

22 PRESIDING MEMBER GEESMAN: Were there
23 questions for Mike?

24 MR. GOPAL: All right, the next in line
25 is Bill Wood. He will talk about -- no, before

1 Bill, we'll have Jim Fore to briefly describe some
2 of the assumptions that led to the building and
3 expansion of LNG facilities, and the new
4 facilities that will be coming into the state.

5 And Jim Fore's talk on LNG will be
6 followed by Bill, who will be talking about the
7 pipeline infrastructure and the implications of
8 what these pipelines are going to do to
9 California.

10 MR. FORE: Good morning. It won't take
11 long to cover the LNG part, but, Todd, to answer
12 your question, it was based upon, at the time,
13 press releases from the companies on when they
14 thought their LNG facilities, regasification
15 facilities would start. And many of those have
16 already slipped because this data was set out
17 probably in September in order to get it into the
18 model and build the structure for the LNG.

19 And so when we revise it we'll slip some
20 of those startup dates for the LNG facilities to
21 match what the current press releases are from the
22 different companies.

23 Also, since that time there have been
24 other facilities permitted that were not permitted
25 at the time, particularly in eastern Canada; the

1 one in Main that we may want to put into the
2 model. And have those costs and supply curves put
3 in and see what the effect would be on the natural
4 gas market.

5 And so we're really moving from a North
6 American to world gas market is what it comes down
7 to, because you have to consider LNG.

8 What we did to put in the LNG cost
9 curves is we went and looked at the cost to
10 produce gas from the wellhead up through
11 regasification in the different various regions of
12 the world. And came up with some cost estimates
13 based upon the expansion of existing units and the
14 building of completely new units. And the ranges
15 you see in the chart are the costs associated with
16 expansion and new units.

17 And includes well field costs,
18 liquefaction costs; transportation we handled on a
19 day rate, rather than looking at shipping and
20 trying to put in the estimate for shipping costs.
21 And then regasification that includes losses along
22 the way so that the production in the field is
23 probably about 120 percent more than what ends up
24 at the regasification in the U.S.

25 We then took a look at the volume that

1 these facilities, both existing and planned, were
2 going to take out of those areas and made sure the
3 reserves in those areas were sufficient to support
4 these plants over a 20-year period in order to
5 include these cost numbers into the supply curves.

6 We then developed a supply curve for
7 LNG, delivering into the east coast, the Gulf
8 coast and the west coast based on these. And
9 that's what the model then uses.

10 PRESIDING MEMBER GEESMAN: And what
11 vintage dollars are these?

12 MR. FORE: They're current; that's 2004
13 is what we based it on, or I based mine on. And
14 then Leon made any adjustments that were required
15 to those dollars to match the model that they were
16 being run in.

17 MR. BRATHWAITE: What goes into the
18 model is really 2000 dollars. So Jim calculated
19 -- when Jim gives me this information, he may give
20 me in 2004, but when I put it in the model it's
21 going to go in as 2000 dollars.

22 PRESIDING MEMBER GEESMAN: And these
23 that are on this chart, and then escalated up to
24 be 2004 dollars, is that right?

25 MR. FORE: These are the ones I

1 calculated in 2004.

2 PRESIDING MEMBER GEESMAN: You calculate
3 them in 2004, but are they 2000 dollars or 2004
4 dollars?

5 MR. FORE: The ones shown here are 2004
6 dollars.

7 PRESIDING MEMBER GEESMAN: Okay.

8 MR. FORE: They're the ones I came up
9 with using the cost estimates based on current
10 dollars.

11 PRESIDING MEMBER GEESMAN: Okay.

12 MR. FORE: He then deflated them to fit
13 into the model --

14 MR. BRATHWAITE: Right, --

15 MR. FORE: -- at the 2000 terms.

16 PRESIDING MEMBER GEESMAN: And if, let's
17 say, a resource was coming online in 2009 in South
18 America, how would that then be treated and how
19 would it show up on this table?

20 MR. FORE: Well, the model runs
21 everything at a constant 2000 all the way through.

22 MR. BRATHWAITE: Yes, --

23 MR. FORE: And so you'd have to go back
24 and take our price forecast and inflate it with
25 some inflation factor to come up to that. It's

1 all treated as constant dollars.

2 PRESIDING MEMBER GEESMAN: Okay.

3 MR. FORE: Okay. This is basically
4 what's going into the Gulf Coast and the east
5 coast of the U.S. And the prices that we have.
6 And they vary from a low of 2.50 coming out of
7 basically Trinidad to a high from the Middle East
8 of 4.85 for a completely new unit into the Gulf
9 Coast.

10 In the east coast it's 2.20, again that
11 would be Trinidad; up to the 5.30 coming out of
12 the Middle East. That costs are what are used to
13 develop the supply curves for the east coast.

14 On the west coast, at the time we were
15 doing it the Bolivian project looked like it might
16 be viable for Marathon, and that's the 4.15 for
17 South America west coast.

18 Then Asian Pacific basically is
19 Indonesia, Australia, that area, the Russian is
20 Sakhlad, and then Alaskan in case they end up
21 putting a pipeline into the coast so they could do
22 LNG.

23 And then we calculated the costs
24 associated with these facilities to come up with a
25 cost estimate for LNG landed in southern

1 California. We only used the Baja southern
2 California transportation to come up with these
3 prices here.

4 Then on the regasification facilities we
5 took the current facilities, added in some
6 expansion, any new facilities. Fort Pelican we
7 already know has been delayed, and that'll have to
8 be shipped at Cameron, the Freeport. We'll make
9 sure that no press releases have indicated that
10 that's going to slip. If it has, we'll have to
11 make those adjustments, as well as to the Baja
12 facility there.

13 And then like I said, there have been
14 some additional ones that have been permitted.
15 And that was one of our criteria, that it had to
16 be at least permitted and under construction. And
17 we'll have to look and see whether we want to
18 include some additional LNG capacity in other
19 locations.

20 If we open the model up the costs we
21 have for the Gulf Coast, we really don't have to
22 indicate what plant it would be. It would just
23 expand the LNG coming into the Gulf Coast. We
24 would not identify any particular facility. It
25 would just indicate that more LNG would be

1 competitive landed in the Gulf Coast or on the
2 east coast.

3 PRESIDING MEMBER GEESMAN: And how have
4 your price assumptions been vetted with others?

5 MR. FORE: Nobody's objected to them is
6 all I can say.

7 (Laughter.)

8 MR. FORE: We presented them about three
9 times. We presented them at the WIEB conference,
10 and we had people in from the industry. We
11 presented them here in a workshop and nobody has
12 really complained about them being too high or too
13 low.

14 PRESIDING MEMBER GEESMAN: And have you
15 compared them with similar assumptions being used
16 by others?

17 MR. FORE: No. We don't have anybody
18 that want to share what they can land LNG for
19 here.

20 PRESIDING MEMBER GEESMAN: But there
21 must be some published estimates --

22 MR. FORE: Well, we've compared them
23 with the stuff EIA and some of the papers on LNG
24 potential. And we're in the same range.

25 PRESIDING MEMBER GEESMAN: Could you

1 make a written comparison for us and submit that
2 to our docket?

3 MR. FORE: Sure, I can get that,
4 compared to other people's, yes.

5 PRESIDING MEMBER GEESMAN: Great.

6 MR. FORE: Any questions, any others?

7 MR. TOMASHEFSKY: Jim, could we just
8 have a clarification just before you leave. Those
9 delivery prices, does that include the commodity,
10 as well, delivered to the various destinations?
11 So is that including the cost of the gas to
12 produce it? Or is that just the transportation-
13 related cost?

14 MR. FORE: The cost I show there
15 includes the production cost, the liquefaction
16 cost, and --

17 MR. TOMASHEFSKY: Oh, it does --

18 MR. FORE: -- and everything through.
19 What I did is I took the regasification facility
20 and I backed through the system adding in the gas
21 losses that would occur due to transportation,
22 going through the liquefaction, and due to
23 extraction of condensate out.

24 And that's where some of the cost
25 estimates can vary greatly depending on the credit

1 you give in terms of, you know, condensate credits
2 you get from taking out of the gas stream.

3 And so if there's a price difference
4 that's probably where it is; it's more in the
5 byproduct values that you might be able to extract
6 than anything else. Or the transportation rate.

7 MR. TOMASHEFSKY: Okay.

8 PRESIDING MEMBER GEESMAN: How do those
9 costs compare with the cost assumptions we made in
10 our 2003 analysis?

11 MR. FORE: I wasn't here when you done
12 that one, so I don't know.

13 PRESIDING MEMBER GEESMAN: Well, that's
14 a question that I'll pose to the management.

15 MR. FORE: Okay.

16 MR. GOPAL: In the 2003 IEPR analysis we
17 did look at some of the LNG analysis. But at that
18 time we didn't have these cost curves developed.
19 We did not even have the alternative competition
20 between various sources. We just had a single, an
21 LNG fictitious source which would deliver LNG to
22 U.S.

23 So there's a big difference in the level
24 of detail that's been included in this analysis.

25 UNIDENTIFIED SPEAKER: Baja was not

1 included there.

2 MR. GOPAL: And Baja, of course, was not
3 even included on the west coast at that time. We
4 had just looked at the potential expansion of the
5 east and the Gulf Coast.

6 PRESIDING MEMBER GEESMAN: And what
7 price assumptions had you associated with either
8 of those two options compared to what you're using
9 today?

10 MR. GOPAL: I think the numbers that we
11 have today are slightly higher than what numbers
12 we had in the 2003 analysis.

13 PRESIDING MEMBER GEESMAN: And what
14 accounts for that difference?

15 MR. GOPAL: Basically the reassessment
16 of the tankering, the liquefaction costs. That
17 actually makes a big difference. Probably the
18 anticipation of what it would cost to produce the
19 gas in various regions still remains the same;
20 it's in the range of 50 cents per mcf to \$1 per
21 mcf.

22 PRESIDING MEMBER GEESMAN: Thank you.

23 MR. WOOD: Well, I get to say good
24 afternoon. Good afternoon, everybody,
25 Commissioners and those who are listening in. My

1 name is Bill Wood; I work in the natural gas unit.
2 I don't know what you're going to call my title, I
3 guess retired annuitant or something like that,
4 but in any event I'm here to talk about
5 interstate, or the infrastructure that we have
6 within the model, and how it's being impacted by
7 the flows.

8 My first slide here deals with three
9 areas. One is the delivery of various interstate
10 pipelines to California; and then comparing that
11 with the California receiving capacity; and then
12 additionally there are two pipelines that receive
13 gas at the California border and pass the gas
14 right on through for use outside the state.
15 Tuscarora received gas, Canadian gas at Malin in
16 Oregon and delivers it to Reno. And, of course,
17 North Baja receives gas from El Paso at Baja and
18 delivers that into Mexico for use there.

19 Now, interesting here, we have less
20 receiving capacity than we have in delivery
21 capacity to California and that's the way it
22 should be, because that provides us then more
23 options to receive gas, and provides competition.

24 But one of the things I want to indicate
25 is that this particular number may be a little bit

1 soft. I say it's soft because if we look at gas
2 transmission north we see that we have included
3 here almost 2 billion cubic feet per day of gas
4 delivery capacity at Malim. But actually that may
5 be considerably less than that, because just above
6 Malim GTN delivers gas to Klamath Falls and also
7 to Tuscarora.

8 So therefore, while we have delivery
9 capacity at about 2 bcf a day, actual deliveries
10 may be in the area of about 1800, and I think
11 that's something along the lines that PG&E uses in
12 their analysis.

13 And additionally, in the wintertime
14 those can actually, deliveries to California at
15 Malim can actually drop to around 1400 million
16 cubic feet a day because of demand that occurs in
17 the Pacific Northwest.

18 So that's one of the reasons I say that
19 while we have these kind of capacities, it's nice
20 to know what it is, but it doesn't necessarily
21 mean absolutely that we're going to be able to
22 have that much gas flowing into the state.

23 MR. TOMASHEFSKY: Bill, does the 6901
24 include the pass-through capacity, also? Or is
25 that the --

1 MR. WOOD: The which?

2 MR. TOMASHEFSKY: The 6901, when you
3 look at it, does that include the 598 that comes
4 as Tuscarora and North Baja?

5 MR. WOOD: No. Those are all pass-
6 throughs. No, those are all pass-throughs. We're
7 not assuming any receiving capacity from those
8 because presently there's nobody -- well, I
9 shouldn't say that.

10 Tuscarora, I think, is dropping off a
11 million a day or something up in Sierra, or what
12 is that, Modoc County, in Sierras. In any event,
13 so.

14 And, of course, this does not include
15 California production, which lays on top of this,
16 which could be in the area of a bcf a day or
17 someplace in that area.

18 Here is a slide you've already seen. It
19 basically says here's the gas that's coming into
20 California from the various sources. The only
21 point I want to make here is that we have
22 receiving in the area of 5500 million cubic feet
23 per day. And the previous slide indicated that we
24 have receiving capacity in the area of about 8
25 billion cubic feet per day. So therefore there is

1 a certain amount of what you might call slack
2 capacity for receiving gas into California on an
3 annual average basis.

4 Now, this next slide is not in your
5 package. I'm basically going to be talking about
6 the next slide that you have, which shows
7 interstate pipeline capacity, but I thought it
8 would be easier to work this off of a map that
9 shows the pipelines rather than working off a
10 graph.

11 Basically if you remember, we have about
12 11 billion cubic feet a day of LNG coming into the
13 U.S. that we have put into the model in terms of
14 capacity. Ten of that sits over here in the Gulf
15 Coast and the eastern seaboard, with a billion
16 cubic feet per day here.

17 And as Mike indicated, this 10 billion
18 cubic feet of supply really is impacting the home
19 for this gas that's being produced in the Anadarko
20 and the Permian Basins. This gas used to flow
21 this way. Because of all the LNG in here, this
22 gas is going up here displacing the gas that's
23 coming out of the Permian and Anadarko, forcing
24 then, a lot of gas to come on El Paso south to
25 California, or at least to serve the southwest.

1 We actually have a surprising change in
2 what we've had in the previous forecast. We had
3 this pipeline running at about 50 to 60 percent
4 capacity in the last IEPR. We have it running now
5 at 155 percent of capacity. Because of the
6 displacement that is occurring on the Permian gas.

7 Additionally, because of the LNG that's
8 coming in here, we have north of this particular
9 pipeline what we call the El Paso North corridor,
10 which includes El Paso, Transwestern and Southern
11 Trails, we have this pipeline now running at about
12 100 percent or 110 percent in the long term. In
13 our previous forecast this was running about 500
14 million cubic feet per day over capacity.

15 So, because of the LNG that has come in
16 that we're using now in the model that we didn't
17 have before, we are seeing a dynamic change in
18 supply flows in the southwest.

19 Now, with regards to deliveries at the
20 California border --

21 PRESIDING MEMBER GEESMAN: Bill, let me
22 stop you.

23 MR. WOOD: Yeah.

24 PRESIDING MEMBER GEESMAN: Is that
25 attributable to a different modeling approach? Or

1 more LNG coming into the Gulf Coast? Or a
2 different price relationship between that LNG and
3 the Permian and Anadarko prices?

4 MR. WOOD: It has to do with LNG coming
5 in.

6 PRESIDING MEMBER GEESMAN: Volume of
7 supply.

8 MR. WOOD: Volume of supply. In fact,
9 we had -- intuitively you would see that that was
10 happening, you know. If you have a tremendous
11 amount of new supply coming here and it's all
12 coming in, it's got to displace somebody's
13 production. And in this case, as far as we are
14 concerned, it's displacing this production.

15 In fact, about three years ago El Paso
16 came in and gave us a presentation that
17 substantiated what we're seeing here, that they
18 threw in a -- before we'd even began to think
19 about putting a lot of LNG in, they'd already done
20 it, into their modeling. And I think that's one
21 of the reasons why they bought the All American
22 pipeline, because they could see that initial 500
23 million cubic feet per day of capacity there. And
24 the need for -- potential need for that capacity
25 to meet this requirement.

1 PRESIDING MEMBER GEESMAN: So in 2003
2 you didn't see as much LNG coming into the Gulf
3 Coast as you do now?

4 MR. WOOD: Well, in 2003 LNG was still
5 kind of a twinkle in daddy's eye, if you would.
6 You know, everybody was talking about it, but
7 nobody had really stepped forward. And we had, as
8 we indicated before, our criteria to putting it
9 in, putting anything into the model should be that
10 it's been permitted.

11 We did do some LNG work on a scenario
12 basis, but not to this degree that we have here.

13 PRESIDING MEMBER GEESMAN: Thank you.

14 MR. WOOD: All right, now, with regards
15 to what's happening here at the California border,
16 Topoc flows here at North Needles, or Topoc,
17 whatever you want to call it, is running at about
18 70 percent, dropping down to about 40 percent.

19 Down here at Blythe it's, we see,
20 running at about 80 percent of capacity. Before
21 it was running at about that same level, but we
22 had gas coming -- in the previous studies we had
23 gas coming this way, and then down across the
24 Havasu cross-over into the southern system to keep
25 that flow.

1 An interesting thing is we have, with
2 the Baja -- I'm sorry, with the new LNG facility
3 here, we see several hundred million cubic feet a
4 day crossing over the border and going in to serve
5 San Diego. Now, that gas can't go anyplace else
6 other than San Diego at the moment because there
7 is no pipeline that will allow it flow north into
8 SoCalGas system.

9 So we have a bcf of gas coming in here,
10 a couple hundred going this way; and if I
11 remember, somebody said we had about up to 600
12 million cubic feet per day of demand in Baja.
13 Which then means the rest of it can flow up to
14 here at Blythe/Ehrenberg, at which point it can go
15 east or west. And so some of that gas could be
16 some of the gas that's coming into California on
17 SoCal's system.

18 At this particular point, at Blythe we
19 can have San Juan gas coming in via -- too many
20 pipes here -- via El Paso Northern corridor and
21 down Havasu. We can have Permian gas coming in,
22 and we can also have LNG coming in. And it's kind
23 of difficult to tell whose molecules are flowing
24 into southern California.

25 One of the shocking things that came to

1 my mind as a result of this analysis is that we
2 had GTN dropping in the area of 40 to 60 percent.
3 And in the past it was running at 100 percent.

4 But I think, while we were putting this
5 together in the last couple of days, I think I
6 discovered a glitch in northern California
7 production. I think we have over-production
8 occurring in northern California, which was
9 therefore backing out some of this, and also some
10 of the Kern River supply. So that's something
11 that, one of those things that was indicated
12 earlier that we need to look at a little closer.

13 Finally, Kern River, we have Kern River
14 running at 95 percent capacity. In our previous
15 analysis we had them increasing at about 500
16 million cubic feet per day in about five years.
17 So that's another difference then between this
18 analysis and the other that is driven, again, by
19 this LNG coming into the Gulf Coast and by LNG in
20 the Baja, California area.

21 MS. JONES: Bill, on the graph here you
22 have TGN running at over 120 --

23 MR. WOOD: Yes.

24 MS. JONES: -- percent capacity. What
25 accounts for that?

1 MR. WOOD: That's LNG coming in from
2 into North Baja and wanting to flow into San
3 Diego. Now, we have -- I think I have 174 million
4 cubic feet per day of capacity on that, which
5 would indicate then, as I said, if it's running
6 125 percent or thereabouts, then that means it's
7 running around a couple hundred million cubic feet
8 per day.

9 And basically that Baja gas is competing
10 with -- let me go back, no, wrong way -- that Baja
11 gas coming across here is competing with gas
12 that's coming down from SoCalGas down this system
13 into San Diego.

14 And I would guess because of
15 transportation charges and the relative cost of
16 the LNG is beating out some of the supply that
17 wants to come in from any of the other sources
18 that feed into SoCal service area. And
19 ultimately, then, would be transported down into
20 San Diego.

21 MS. JONES: Okay. I'm wondering
22 physically how you put 125 percent gas through the
23 pipeline.

24 MR. WOOD: Oh, it just means that the
25 pipe is going to have to be expanded.

1 MS. JONES: Okay, thank you.

2 MR. WOOD: Any time our model shows 100
3 percent or 150 percent it's building pipe to take
4 that into effect -- or to take care of that.

5 MS. JONES: So then it's assumed that
6 some additional infrastructure comes in in the
7 model?

8 MR. WOOD: Yes.

9 MS. JONES: Okay.

10 PRESIDING MEMBER GEESMAN: But if I
11 understand the model correctly, it's adjust in
12 time equilibrium. So the assumption is that the
13 infrastructure is there when you need it to be,
14 and that you don't create imbalances either on a
15 surplus or a deficit basis, is that right?

16 MR. GOPAL: (inaudible).

17 MR. WOOD: Yeah, let the modelers --

18 MR. GOPAL: Yes, Commissioner, what you
19 said is absolutely correct. Okay. However, if,
20 for instance, there is some reason that we believe
21 that something will not be available when we need
22 it, we can put that into the model.

23 PRESIDING MEMBER GEESMAN: Sure.

24 MR. GOPAL: However, there's a
25 consequence to that, which would be higher prices.

1 PRESIDING MEMBER GEESMAN: Sure.

2 MR. GOPAL: So there is always, you
3 know, wherever, for instance like the LNG
4 situation I spoke about this morning, we have it
5 capped. So because of that we may see higher
6 prices in some locations. If we release the cap,
7 then the thing will expand as it see fit, and
8 prices may -- we may see some softening in prices.

9 PRESIDING MEMBER GEESMAN: Right. Thank
10 you.

11 MR. GOPAL: Sure.

12 MR. WOOD: Well, we don't need to talk
13 about that. Let's just kind of summarize things
14 up a little bit here.

15 Basically we see that LNG will have an
16 impact on western states pipeline flows and in
17 California supply; in other words, where that
18 supply is coming from.

19 Our preliminary analysis indicates the
20 state has adequate receiving capacity, at least on
21 an annual average basis. Remember we compared
22 that, I don't remember what the numbers were,
23 about 5.5 billion cubic feet versus about 8
24 billion cubic feet of receiving capacity.

25 Pipes serving California will have lower

1 flows than in the previous analysis that we have
2 done, except for El Paso south, which will have
3 increased its flow. And I should also indicate
4 again, reiterate that El Paso north is not flowing
5 as full as it did before. But will potentially
6 need a small amount of capacity, because we have
7 it running at 100 to 110 percent of capacity
8 during the time period which may or may not be
9 warranted, adding capacity, but may force supply
10 coming in from another location.

11 That concludes my presentation. If
12 there's any questions, or any additional questions
13 from --

14 PRESIDING MEMBER GEESMAN: I'm trying to
15 reconcile your third bullet on that page with the
16 increased flows west that you showed.

17 MR. WOOD: Increasing Gulf Coast LNG --

18 PRESIDING MEMBER GEESMAN: No, third
19 bullet.

20 MR. WOOD: Oh, okay. Basically maybe
21 the word delay is not the proper term. It may
22 actually forestall the need of additional capacity
23 other than, as I indicated, the El Paso north and
24 specifically the El Paso southern systems.

25 PRESIDING MEMBER GEESMAN: Which are

1 both new interstate pipeline capacity into
2 California.

3 MR. WOOD: The capacity would be
4 required to actually not serve California because
5 we're operating at the California border below
6 their delivery capacity. Those increases would be
7 to meet east of California requirements --

8 PRESIDING MEMBER GEESMAN: I follow it.

9 MR. WOOD: And particularly El Paso
10 south, take care of that huge growth in generation
11 capacity in southern Arizona.

12 PRESIDING MEMBER GEESMAN: Yeah, I
13 follow you now. Thank you.

14 MR. BRATHWAITE: Commissioner Geesman, I
15 just wish to expand on a question you asked
16 earlier about whether we had changed any of our
17 modeling techniques or anything like that.

18 We basically have not changed the
19 modeling technique. I mean there are a few more
20 bells and whistles in the model, but the
21 technique, itself, have not changed.

22 But what have changed and have changed
23 significantly in this runs is that we have
24 included a lot more structure, both within the
25 U.S., and even more important, connecting to the

1 rest of the world to LNG. That is something that
2 we really did not have previously. So that is the
3 most significant change that we have had in the
4 model, itself. Not the technique, itself, but the
5 structure and its connection to the world, and
6 making LNG -- making natural gas become a world
7 commodity rather than it be limited to the North
8 American continent.

9 PRESIDING MEMBER GEESMAN: Yeah, but if
10 I am understanding your presentation correctly,
11 over the course of two years with not a
12 significant price change in landed LNG on the Gulf
13 Coast, you have made a fairly large secular change
14 in your assumption about gas from the Permian
15 Basin and Anadarko Basin flowing westward.

16 MR. BRATHWAITE: Yeah, that is a model
17 result. That's not an input result.

18 PRESIDING MEMBER GEESMAN: No, I
19 understand it's a modeled result, but it is a
20 large enough change that I think it needs to be
21 explained to the various constituencies which our
22 process ultimately has to address.

23 MR. BRATHWAITE: Point well taken, yes.
24 Yes, sir. Thank you.

25 PRESIDING MEMBER GEESMAN: Thank you.

1 MR. MAUL: Commissioners, given the hour
2 it is, 1:00, do you want to continue marching on
3 with price, or take a lunch break or --

4 PRESIDING MEMBER GEESMAN: Why don't we
5 break for lunch; come back at 2:00.

6 MR. MAUL: 2:00? Okay. Will do.
7 (Whereupon, at 1:00 p.m., the hearing
8 was adjourned, to reconvene at 2:00
9 p.m., this same day.)

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1 AFTERNOON SESSION

2 2:08 p.m.

3 MR. GOPAL: Thank you, Commissioner.

4 We, in the morning, started talking about natural
5 gas demand. Then we switched to supplies and we
6 have talked about infrastructure, LNG and
7 pipelines. All of this boils down to one thing,
8 and that is price. What is it that you have to
9 pay for it.

10 Mark will talk about some of the price
11 implications that we see in our preliminary
12 reference case. Mark.

13 MR. DiGIOVANNA: Hopefully nobody has
14 the after-lunch sleepies for this portion. This
15 will be considerably shorter than the demand
16 section, I promise you that.

17 So, what I'm going to go over today is
18 the natural gas wellhead prices that we're
19 projecting, or that basically our model is giving
20 back to us. And then go through each of the end
21 use sectors, and go through what the price results
22 are for those.

23 And then at the very end I just wanted
24 to kind of initiate a discussion, just because
25 it's been talked about a lot behind the scenes, of

1 how we, in the course of coming up with an
2 electricity generation forecast, we need to
3 convert the annual prices in the model to monthly
4 prices, so that the electricity office can use
5 those. So get into a little bit about how we do
6 that. And more just to kind of facilitate
7 discussion than anything else.

8 First slide here is the projected
9 wellhead prices for the basins that supply
10 California. As you can see, compared to price
11 forecasts that we've given in the past this is,
12 you know, definitely a lot more of a sawtooth
13 projection than what we've seen in previous
14 reports.

15 A couple reasons for that. One of them
16 is just the fact that we are looking at things on
17 an annual basis rather than every five years. The
18 other reason is that there are, you know,
19 introducing things like LNG, MacKenzie and Alaska
20 pipelines. There's a lot of things going on that
21 keep changing the price trajectory that we're
22 seeing here in the model.

23 So the first thing here, first thing
24 worth noting is what you see in 2007. And that is
25 the Cameron LNG terminal that goes into the Gulf

1 of Mexico. That has about 1500, or 1.5 bcf per
2 day, to the Gulf of Mexico. And this is something
3 that Bill and Mike discussed earlier.

4 This is where we're seeing the gas from
5 the Permian Basin start to get pushed westward as
6 we introduce a large supply into the Gulf of
7 Mexico. And you can see this in the very first
8 time point 2006, the Permian is the highest priced
9 supply. As the forecast goes on it actually ends
10 up becoming one of the lowest price supplies.

11 The next event worth noting is the
12 following year. We have the Costa Azul terminal,
13 Semptra's terminal, down in Baja, Mexico coming
14 online. And what you'll notice, you know, this is
15 something that kind of brings out something that
16 came in Jim's presentation, where you see 1.5 bcf
17 of LNG go into the Gulf of Mexico. You get a
18 dramatic drop in prices.

19 The following year you have 1 bcf go
20 into Baja, Mexico and you don't see a big drop in
21 prices. And there's some reasons for this. One,
22 probably the most fundamental reason, is the
23 relative cost between the two. A terminal in the
24 Gulf of Mexico on the east coast has access to
25 supplies from Trinidad, which tend to be some of

1 the lower cost supplies. Versus a terminal on the
2 west coast needs to go further out to Australia,
3 Indonesia, places like that. So there's a lot
4 more transportation involved and a lost more cost
5 to get it here. So it's not going to be as low
6 cost once it arrives.

7 The other thing that happens is that a
8 fair amount of this gas is consumed within Mexico.
9 Some of it does come up through TGN into the San
10 Diego area; some of it does wheel around North
11 Baja to the Ehrenberg area where it could come
12 into the state, but all along the way it's
13 incurring transportation costs. It's not going to
14 have the same impact that Cameron does going right
15 into a major gas supply area.

16 So the next, kind of change in trend
17 here in the price forecast is the MacKenzie
18 pipeline. Now, we had in the presentations that
19 were given before this, that we have MacKenzie
20 coming on in 2010. It actually has a partial
21 capacity that begins flowing in 2009. We don't
22 get the full capacity until the following year.

23 So where you see the change in the price
24 trend there in 2009, that's actually from the
25 initial flows of MacKenzie. The following year

1 when we go, I think, from about 900 million cubic
2 feet per day to about 1750 you see an actual
3 change in the trend so we get prices actually
4 declining in that year.

5 The next kind of item on the timeline we
6 want to go through is when we have the Alaska
7 pipeline coming in. And like you heard before,
8 that comes online in 2013. Like MacKenzie, it
9 initially flows at a lower volume than it will
10 ultimately. And so you do see a change in the
11 price trend when it comes on in 2013. And you see
12 decreasing prices the following year.

13 In the out years of our forecast, 2015,
14 2016, couple things going on. We have, basically
15 we've added new supply to the model, but you have
16 demand catching up with it. And also we're seeing
17 kind of the effect of capping off the LNG capacity
18 expansions.

19 So, even though Alaska pipeline comes
20 on, very quickly that capacity is used, and that
21 supply is used. And ultimately we end up resuming
22 this higher price path.

23 PRESIDING MEMBER GEESMAN: And that what
24 you called capping off the additional LNG supply
25 capacity, that's a function of your holding that

1 capacity to an original installed amount, as
2 opposed to allowing the model to force it upward?

3 MR. DiGIOVANNA: Right. Kind of going
4 to Melissa's question earlier on the
5 infrastructure where you're seeing pipeline flows
6 that are 155 percent of the capacity. Basically
7 the reason that's happening is because the model
8 has gone ahead, you know, found that even with the
9 additional cost it's economical to expand the pipe
10 and flow gas.

11 You would probably do the same thing
12 with LNG other than the fact that we've turned
13 that part off and said it can't do it.

14 PRESIDING MEMBER GEESMAN: Right.

15 MR. DiGIOVANNA: So, --

16 PRESIDING MEMBER GEESMAN: Right.

17 MR. DiGIOVANNA: -- you know, you end up
18 having, you know, demand kind of bumping up on the
19 supplies there, and you see it resume the higher
20 price path.

21 Now one thing that I kind of skipped is
22 what's going on in western Canada in 2012. To be
23 honest, I don't know 100 percent. By going
24 through the results one thing that we notice
25 throughout basically the entire forecast horizon

1 we can see that conventional production in Alberta
2 is declining.

3 And with the addition of new resources,
4 particularly the MacKenzie pipeline, up until
5 about 2011 there still seems to be inadequate
6 balance as far as, you know, having enough supply
7 to meet demand without causing any real pressure.

8 Just looking at the way the supplies are
9 in Canada during this time period, you kind of get
10 a lull right at 2012 where MacKenzie's come in;
11 that gas is being used, or that capacity has
12 basically been used up. And Alaska hasn't come in
13 yet, and you just kind of get a flat point there.
14 And at the same time demand is increasing.

15 So, it just so happens because the
16 dominant supply source at that point up in Canada
17 is the Alberta conventional supply, that
18 conventional supply is declining so it's moving up
19 its supply curve. You end up getting, you know,
20 Alberta kind of breaking away from the rest of the
21 price trend that we see in the other supply basins
22 that supply California.

23 You can see that it also does affect
24 California's prices a little bit just because a
25 lot of that Alberta or western Canadian gas would

1 come to California, so it's causing some pressure
2 on, increased pressure on the California supplies.
3 And this is something that Bill mentioned earlier
4 where it appears that there might be less
5 utilization of the GTM pipeline because of
6 California production. And you're kind of seeing
7 the result of that here, is that once the Alberta
8 supplies go up, that affects northern California.
9 You see the California production price go up.

10 COMMISSIONER BOYD: Mark, how much of
11 that Alberta gas have they set aside, as they did
12 a couple years ago, for their own use in the
13 bitumen production process? Which caused a
14 decline a year or two ago, that caused a
15 decline --

16 MR. DiGIOVANNA: Actually, --

17 COMMISSIONER BOYD: -- of gas.

18 MR. DiGIOVANNA: -- what happened, if
19 I'm thinking of the same thing, a couple years ago
20 they had actually restricted quite a bit of access
21 to gas reserve, I think in like the Athavaskan --

22 COMMISSIONER BOYD: Right.

23 MR. DiGIOVANNA: -- region.

24 COMMISSIONER BOYD: That's it.

25 MR. DiGIOVANNA: Because they were

1 concerned that it would affect the recovery of the
2 oil sands. A lot of those -- when initially they
3 put that into place and a lot of those companies
4 were actually able to go back and get exemptions,
5 and to continue to produce.

6 I don't know exactly -- from what I know
7 I haven't seen them move to make any more gas
8 production off limits. I don't think that's what
9 we're seeing here in the Alberta prices.

10 So, I mean we could look into this more
11 to see if how that's affecting, but I haven't seen
12 any moves to actually further restrict access.
13 And, if anything, they've actually kind of backed
14 off what their initial restrictions were by
15 allowing some of these companies to get exemptions
16 and still produce.

17 MR. GOPAL: (inaudible).

18 MR. DiGIOVANNA: Right. What Jairam was
19 just saying, the model's not segregating any
20 supplies for oil sands. But actually I think the
21 question there was actually if anything was being
22 restricted. And there's nothing in the model that
23 we've put in there that's doing that. And as far
24 as I know, Alberta hasn't actually made any
25 further moves to restrict gas production because

1 of oil sands.

2 So, that's my guess on why that happens.
3 It's not a guess -- I mean an educated guess, but
4 a guess, nonetheless. We're going to look into it
5 more, but that's what we're seeing right now on
6 that.

7 COMMISSIONER BOYD: Which do you have
8 the most confidence in? Your estimate of when
9 MacKenzie comes along, or the Alaska pipeline
10 comes along?

11 MR. DiGIOVANNA: Oh, in --

12 COMMISSIONER BOYD: That's a good after-
13 lunch question.

14 MR. DiGIOVANNA: Let's see, which one's
15 further away. You know what, --

16 COMMISSIONER BOYD: You're not --

17 MR. DiGIOVANNA: -- I don't know --

18 (Parties speaking simultaneously.)

19 COMMISSIONER BOYD: Okay.

20 MR. DiGIOVANNA: Ask me when I'm not at
21 a podium.

22 MR. MAUL: Commissioner, if I just may
23 add, we follow that weekly, both the Canadian
24 government and the Canadian politics, as well as
25 the Alaskan government and Alaskan politics on

1 both pipelines. And there's a tremendous amount
2 of controversy on both of them. And a tremendous
3 amount of uncertainty on both of them.

4 So I think it's very difficult at this
5 time to really come up with a firm date that we
6 have a lot of confidence in. At least I've been
7 watching it changes dramatically every single
8 month. And it's getting between international
9 trade agreements between Canada and the U.S. It
10 gets between the Canadian government and First
11 Nation Tribes up there. A dispute that's all of a
12 sudden appear to be blow up, and then are
13 resolved. And the next one blows up.

14 So there's a lot going on that it's very
15 difficult for anybody to forecast.

16 COMMISSIONER BOYD: Right. So the
17 certainty with which we put things in here is -- I
18 understand why you do what you do; it's just like
19 talking about 150 percent of capacity. I'd put
20 more stock in the ability of somebody to decide
21 that they want to build that additional pipeline
22 in those examples.

23 But all of those are speculative and
24 just --

25 MR. MAUL: Um-hum, that's right.

1 COMMISSIONER BOYD: -- enter into the
2 uncertainties, the unknowns that affect ultimately
3 the price we pay, which has been variable as heck.

4 PRESIDING MEMBER GEESMAN: These two
5 projects, MacKenzie and Alaska, were two where you
6 varied from your criteria for infrastructure?

7 MR. MAUL: That's right, those are the
8 only two projects where we did just because
9 they're such significant projects. They have been
10 talked about for so long; they've been planned for
11 so long. They're like the elephant in the room,
12 we can't ignore it. We have to do something with
13 it. We uncomfortable with pinpointing what we do
14 with it, but the model requires us to pick a date,
15 put it in there. And we could easily move the
16 date by two or three years and probably have just
17 as equally valid model result.

18 PRESIDING MEMBER GEESMAN: And have you
19 done that and determined what the impact on
20 wellhead prices would be?

21 MR. MAUL: Not yet, but we have the
22 capability to do that now very quickly.

23 PRESIDING MEMBER GEESMAN: Okay.

24 COMMISSIONER BOYD: Wait till I ask you
25 to start playing with syngas some day.

1 (Laughter.)

2 MR. DiGIOVANNA: All right. The next
3 couple charts I'll probably move through
4 relatively quickly only because what you're seeing
5 here in the end use price for residential and
6 commercial and industrial customers is basically
7 just a reflection of the chart that I just showed
8 you.

9 All of these follow the same trend as
10 the wellhead prices. Basically the difference
11 between the two is going to be the transportation
12 to get it to California; then the cost to
13 distribute it to customers.

14 In this first graph here you can see
15 that these are the prices to residential
16 customers. The highest priced area is the San
17 Diego area. The reason for this is they actually
18 need to move their gas through another utility's
19 service territory before they can get it to their
20 customers.

21 Until Baja goes on line -- I'm sorry,
22 not Baja -- the Sempra's Costa Azul terminal goes
23 on line and if gas moves up TGN, SDG&E actually
24 doesn't have any direct access to an interstate
25 supply. So, you're seeing that here reflected in

1 the higher costs to bring gas to their customers;
2 with SoCal just slightly higher than PG&E.

3 In the commercial sector you get a
4 little bit of a flip-flop here. You get PG&E
5 becoming the highest priced service territory for
6 commercial service, and SDG&E kind of being in the
7 middle. That's just a reflection of the rates
8 that they charge those types of customers.

9 So, again, it's following the same trend
10 that we saw before. The costs that are charged to
11 commercial customers are less than they are at
12 residential, so if this forecast were put on the
13 same graph as the previous, the residential prices
14 would be up at the top, and then the commercial.

15 And then as we get into the industrial
16 customers, here's where you start to see a lot
17 less differentiation between the different service
18 territories. And the reason is just because of
19 the type of customers. The industrial customers,
20 there's fewer customers; it's easier to meter
21 them.

22 They're not getting into the really vast
23 distribution systems that need to go to the
24 millions of different customers that are in these
25 service territories. So there's a lot less cost

1 involved to the utilities. And so that's -- you
2 see that in a lot less of a markup.

3 And on top of that a lot of the larger
4 industrial customers actually go out and procure
5 their own gas, so they're not paying core
6 procurement or things like that.

7 As far as why chemical customers in
8 SoCal are lower than the rest, I don't know. I
9 think we need to check that. That might just be
10 something in the transportation rate we have in
11 there.

12 Conversely, on the enhanced oil recovery
13 customers, the lower prices you're seeing there is
14 a reflection of the fact that they are, for the
15 most part, located right along the Kern/Mojave
16 corridor. They have access to interstate pipeline
17 capacity versus having to go through utility
18 system. And in many instances there's actually
19 local gas production going on that's used for the
20 thermally enhanced oil recovery. So they're not
21 even incurring any interstate transportation
22 charges. So that's why you see the gas prices of
23 those customers so much lower than the rest of the
24 industrial customers.

25 All right, finally the projected natural

1 gas prices for power generation customers. Kind
2 of a lot going on in this graph because we have a
3 lot of different customer types here.

4 Like I mentioned earlier before you have
5 the customers that are operating within the
6 utility systems. You also have customers that are
7 operating directly off the interstate pipelines.

8 So, as a result you're getting kind of
9 an array of rates that are charged. In addition
10 to this, in the PG&E area PG&E actually was able
11 to adopt a rate structure that allowed them to
12 charge basically the new power plants. I mean, I
13 think the order says power plants built after
14 1998, but we all know that nobody actually built
15 them until the lights started going out.

16 So basically it's the new power plants
17 that are getting this rate. They're paying about
18 a nickel above the PG&E citygate price. Whereas,
19 the older power plants are paying an additional 14
20 cents above that.

21 So when you see the solid blue line at
22 the top of this graph, that is the older power
23 plants that are being charged both the backbone
24 rate, and a local distribution charge. Below that
25 you will see the PG&E plants that are just paying

1 the backbone rate.

2 It doesn't look like it in here, but the
3 SoCalGas and SDG&E customers right now do actually
4 pay a slightly different transportation rate.

5 It's a few cents different, a few cents higher for
6 SDG&E.

7 And the rest, as you move down here,
8 it's just this is just basically the cost of gas
9 based on where they're getting -- which pipeline
10 are they getting their gas from. What supply
11 basin does that pipeline have access to. So
12 that's where you're seeing this kind of array of
13 prices here.

14 All right, the last chart here is the
15 profiles that we used to take a yearly price and
16 convert it into a monthly price. And actually I
17 might call Bill up here, because this methodology
18 here was developed by Bill.

19 Basically what he's gone through, and
20 he's looked at the prices that are reported on,
21 it's both the bid week and the spot prices, is
22 that correct? I'll let Bill come up and --

23 MR. WOOD: What I have here is a
24 sampling of monthly allocation factors that
25 developed for several regions, PG&E, Southern

1 California, El Paso South representing the Arizona
2 and Pacific Northwest. And I threw in here Henry
3 Hub, which we don't use, but just to show that the
4 trajectory follows the same as we have for the
5 factors that we're using for converting annual
6 prices into monthly prices for the electric
7 generators.

8 Basically, what I have done is I have
9 gone from 2002 to 2004 looking at prices, monthly
10 average prices published by NGI at various
11 locations throughout the western states. I've
12 gone to Lippman Consulting and come up with the
13 volumes that are associated, the actual flowing
14 volumes that are associated with those particular
15 points. And then developed a weighted average
16 price for those three years.

17 There's been a lot of controversy in
18 some of the work that's being done in what is it,
19 CREPC or -- with regards to this, because they
20 don't like the idea that January prices look like
21 they're going to be lower than the previous
22 December prices as these factors would indicate.

23 If you look you'll see generally factors
24 are in the area of about 95 percent of the annual
25 for January; and in the previous December they'll

1 be running about 115 percent. But basically that
2 is what has happened during the last four years.

3 They would prefer to see something that
4 has January and December closer together than what
5 is shown here. For the CREPC work they've
6 actually gone through and looked at NYMEX strips
7 for 2007, '8, and to apply to their 2008 point
8 that they're forecasting. And they get something
9 that they're happier with that show factors that
10 are closer together.

11 So the question arises then do we -- I
12 don't feel comfortable using three points for each
13 month to develop this particular curve, but
14 nevertheless, it still is representative of what
15 has been happening in the last three years.

16 And it's basically because January
17 prices -- well, no, let's not say that, that's not
18 correct. I'm thinking ahead of myself here.

19 So, anyway, that's the controversy
20 that's going along here. Do we look at the -- use
21 a historic set of numbers to work with? We don't
22 want to use the 2000/2001 numbers because the
23 world was crazy during that particular time. And
24 the question also then arises, then well what
25 about 1990 through 1999. I have developed factors

1 for that. But is that regime still the same as we
2 can see now with regards to prices on a seasonal
3 basis.

4 So we're in a quandary at this point
5 whether to use futures or whether to use the last
6 three years, or to use a whole previous three or
7 ten years worth of data to come up with these
8 seasonalities.

9 I'm not certain that the big months for
10 generation would be affected too much. And that's
11 when the large demand for generation would occur.
12 The winter months the demand is not so great so it
13 may not have as great an impact whether you use
14 higher factors or lower factors for those
15 particular months.

16 But, in any event, we're looking for
17 comments in this particular area from whomever has
18 a thought on this. And we need to have this
19 information fairly soon so that we can provide
20 additional information for our electricity office
21 so that they can continue to do their work.

22 As indicated earlier, we dovetail with
23 them. And there's an iterative process that
24 sometimes takes a week or two to run through just
25 one process. So we'll develop a price forecast.

1 They'll take three or four days or whatever to
2 develop a new demand forecast. We put that into
3 our forecast, and then that iterative cycle might
4 take ten working days or so to go through.

5 So, we need to get this resolved soon so
6 that we can meet the deadlines that we're looking
7 at.

8 PRESIDING MEMBER GEESMAN: Okay, I have
9 a blue card from Wendy Maria Phelps from CPUC.
10 She has a couple of questions.

11 MS. PHELPS: Yeah, I think the first
12 question, Mark, is about the presentation that
13 you're giving now. And I'm just wondering how
14 comfortable are you with the amount of decreased
15 prices in 2007 that you were showing due to the
16 addition of the Cameron LNG project?

17 MR. DiGIOVANNA: I don't know, you know,
18 if comfort's really a word I would use. The thing
19 you have to remember, there's actually a couple
20 LNG terminals I believe that should begin
21 operating this year. And when Cameron comes in
22 that's another 1.5 bcf of supply there.

23 And this is really the first time we see
24 such a pushback on the Permian supplies back
25 towards California.

1 So, you know, will there be a, you know,
2 \$1.50 drop in prices, I don't know. But I do
3 think, you know, it is very plausible that we will
4 see a drop in prices in California just from the
5 introduction of such a large LNG, you know, an
6 incremental LNG resource because there is already
7 LNG there.

8 So, you know, what that magnitude will
9 be, I can't say. I mean this is what the model's
10 telling us. But, you know, the fact that there is
11 a drop doesn't concern me. That's actually very
12 plausible.

13 MS. PHELPS: I guess just maybe it seems
14 like that one could have a couple of scenarios,
15 you know, with different amounts of drops.
16 Because it just seems like \$1.50 is pretty --

17 MR. DiGIOVANNA: Well, the -- I mean,
18 yeah --

19 MS. PHELPS: -- is a lot, but --

20 MR. DiGIOVANNA: -- you have to
21 remember, we don't -- price isn't something we
22 give to the model. The model gives it to us. I
23 mean we put, you know, the supplies in there, we
24 put the demand in there, we put the transportation
25 capacities and the rates on those pipelines.

1 And from there we hit run and the model
2 tell us, you know, what is the equilibrium of
3 quantity and price at every point in the model.
4 So the prices we're seeing here aren't really a
5 reflection of price inputs that we're giving.
6 This is -- we've told the model what the supply
7 and demand is, or at least given it a reference to
8 start with on the demand, since most of that is
9 elastic. And this is the result that we're
10 getting.

11 MS. PHELPS: Okay, thanks. My next
12 question actually had to do with morning
13 presentations, and we talked about this at the
14 lunch break a little bit, but I wanted to -- and I
15 think I know the answer to my question, but we
16 both, Mark and I, agree that it should be put on
17 the record.

18 PRESIDING MEMBER GEESMAN: Okay, let's
19 do that now.

20 MS. PHELPS: Basically I just wanted to
21 clarify was the CEC forecast data that was used by
22 the utilities, both PG&E and SoCal and SDG&E, in
23 their presentations when they were comparing to
24 their own forecast from the electricity demand
25 analysis office rather than the natural gas office

1 data? Since the latter was used in the natural
2 gas assessment market report.

3 MR. DiGIOVANNA: The comparisons,
4 correct me if I'm wrong on this, but the
5 comparisons that the utilities gave earlier were
6 actually to the demand analysis office natural gas
7 forecast.

8 With the exception of the comparison to
9 the gas demand for electricity generation, that
10 was actually generated by our electricity analysis
11 office and used in our report.

12 So the comparison that was shown earlier
13 in terms of residential, commercial and industrial
14 demand was actually not a comparison to the demand
15 that is in this report.

16 MS. PHELPS: So now were you going to be
17 working with the demand analysis office to -- I
18 don't know how much difference in their forecast
19 there was with yours.

20 MR. DiGIOVANNA: There were some
21 differences. I mean, and this is something that
22 we need to work through. It's, you know, right
23 now it's a question of different methods, you
24 know. One of the things we were looking to do in
25 this cycle was to incorporate price elasticity

1 into our forecast.

2 And the way we were able to do that was
3 with the different methodology than we've used in
4 the past. So, in terms of reconciling the two
5 forecasts, I think it would be more, you know,
6 looking to make sure that we're consistent in our
7 assumptions. Looking to make, you know, one issue
8 which I think you're going to ask about next, is,
9 you know, basing our forecast on the same data
10 set.

11 So, there will be ways, you know, to
12 look to make them more consistent. And, you know,
13 there will probably be a lot of discussions as far
14 as how we do natural gas demand.

15 MS. PHELPS: That's all, thanks.

16 PRESIDING MEMBER GEESMAN: Mark Meldgin,
17 PG&E.

18 MR. MELDGIN: Thank you. Mark Meldgin
19 with PG&E. I'll be back up again later to offer
20 several comments on modeling after Bob Howard and
21 some others talk. But for right now I wanted to
22 talk about Bill Woods' issue about how to take an
23 annual price on a market builder and split it into
24 12 monthly prices.

25 We haven't seen the exact method that

1 the staff uses, but I have a feeling that what
2 they're doing is taking say PG&E citygate, pick
3 that as an example. Let's look at 2002. And in
4 that year, December 2002 was 20 percent higher
5 than January 2002. In 2003 we see the same thing.
6 In 2004 we see the same thing.

7 So, we come up with these factors
8 December's a lot higher than January. But the
9 real reason for this is just that gas prices have
10 been going up continuously over that period.

11 So, the PG&E price in December of any
12 given year is a lot more closely linked to the
13 prices at Malim, Topoc, et cetera, in that same
14 month than they are linked to the PG&E citygate
15 prices in January of that year.

16 So, what we suggest is instead of, for
17 each point, taking a slice across the months, kind
18 of like averaging across the rows, instead look at
19 the differences in a column. Take January 2002
20 and say, okay, in January 2002 PG&E's citygate was
21 20 cents higher than Malim. In January 2003 it
22 was 15 cents higher than Malim. In January 2004
23 it was 32 cents higher than Malim.

24 Average those three. Do the same for
25 all the hubs around the west, so that you get a

1 set of factors for January that reflect the actual
2 differences in prices around the west over the
3 past three Januaries. Do the same for February,
4 March and so on.

5 So in a sense we're talking about
6 averaging within a month across geography instead
7 of averaging across time at one point. And I
8 think that would do a lot to take care of the
9 staff's issues.

10 Anyway, that's that. Thank you.

11 PRESIDING MEMBER GEESMAN: Thank you
12 very much.

13 MR. DiGIOVANNA: Well, actually I just
14 want to comment on that real quick. One thing
15 that at least I've observed, and I think Bill's
16 observed the same thing, going through the monthly
17 prices, in a lot of instances the January and
18 December differences aren't, you know, January of
19 this year and then 12 months later. It's actually
20 a lot of times it is December of the previous
21 year, you know, December to January.

22 And particularly if you're just looking
23 at the electricity generation sector. I haven't
24 been able to completely work through this, but I
25 mean I think there are reasons for it. A lot of

1 that having to do with Christmas.

2 During December businesses stay open
3 longer; people put extra lights around their
4 house. There is a slight bump in electricity
5 demand that's not explained by weather or anything
6 like that. In January that all goes away.

7 The other thing is that in January
8 basically in terms of electricity generation it's
9 going to be probably your lowest demand month, if
10 not one of your lowest demand months. And so for
11 operators that are purchasing gas, some sort of a
12 baseload supply of gas for their power plant,
13 their baseload's probably going to be based
14 somewhere around what their January, or what their
15 low demand is. And then they'll go out and
16 purchase additional supplies as necessary.

17 So that in January you don't -- there's
18 less of a demand for electricity generators to go
19 out and buy gas on the short-term basis, which
20 tends to be more costly than gas supplies they've
21 locked up, you know, months in advance.

22 This is just my hypothesis on what might
23 explain this. But that part I don't know. What I
24 do know is just looking at the prices, I have
25 consistently observed the difference where

1 December you have prices, you know, here and then
2 the following month you get a dropoff in gas
3 prices for electricity generators.

4 Now, for, you know, a core customer
5 that's not the case. Because, you know, that's
6 when their peak demand is. But for electricity
7 generators, I think it's just because they're able
8 to not have to go out and buy incremental supplies
9 at a higher cost during that time of year.

10 As I say, it's a hypothesis. I don't
11 know.

12 MR. MELDGIN: I'll look at the data and
13 see if I agree with that.

14 MR. DiGIOVANNA: Okay.

15 MR. MELDGIN: One other comment I wanted
16 to make about the staff's method. Bill mentioned
17 that he's constructing a weighted average using
18 prices and volumes. And to me that seems like
19 double counting, because the prices, especially
20 the price differences between different points
21 around the west, already reflect the flows.

22 So I think he's over-weighting that
23 factor. Thank you.

24 PRESIDING MEMBER GEESMAN: Thanks very
25 much. Jairam.

1 MR. GOPAL: We'll take that into
2 consideration, too. In fact, the monthly
3 allocation has been a significant point of
4 discussion with the WECC and other groups that
5 have been looking at electricity generation in the
6 western states.

7 So we will continue to discuss on that
8 point, and get any other updates we get from the
9 other side.

10 Having concluded Mark's testimony I
11 would like to call Herb Emmrich to continue with
12 the second part of his comments on the preliminary
13 case.

14 MR. EMMRICH: Thank you very much. I
15 also cover the gas supply issues for SoCalGas and
16 San Diego Gas and Electric.

17 We think there is plenty of natural gas
18 resource available in the United States and in
19 Canada. The problem is they are in
20 environmentally sensitive areas, offshore,
21 national parks, wildlife preserves and so on. And
22 also in very remote locations like Alaska and the
23 MacKenzie Delta.

24 So it's a matter of willingness of the
25 oil companies to explore and develop. What we're

1 seeing now is the companies are shifting more
2 toward LNG, saying that they can deliver LNG
3 cheaper than they can bring gas from very remote
4 locations or go into tight sands or into shale gas
5 and so on. So this is a phenomena that we see is
6 happening, and I think the staff pretty much
7 reflects some of that.

8 We've always thought that unconventional
9 supplies are probably available at \$4 to \$5 per
10 million Btu. So that almost puts like a lid on
11 prices going out in time, plus transportation, of
12 course. And when I get to the gas price forecast
13 that we have, you know, it'll show that.

14 As far as what the state can do,
15 whatever restrictions there are on exploration and
16 development, you know, to hurry up the permitting
17 process and maybe allow some development in areas
18 that are sensitive to see if it can be done in an
19 environmentally acceptable way. But it's
20 certainly those kinds of issues that are keeping
21 us from developing the resource that's available.

22 LNG throughout the world is becoming a
23 bigger and bigger player. LNG will be almost like
24 oil. It'll move cargos throughout the world.
25 There are something like 40 liquefaction

1 facilities under consideration; and in the U.S.
2 there are more than 60 LNG receiving terminals are
3 being considered. Two more just got approved,
4 which I don't think were reflected in the
5 forecast. There are seven approved now by the
6 FERC. There was one in Massachusetts and one, I
7 think, in Rhode Island which just was approved two
8 weeks ago.

9 So, LNG is coming. But we don't know
10 where it's gong to come, certainly in the Gulf of
11 Mexico, in Baja, those facilities will be built.
12 We don't know about California or the east coast.
13 There's concern of tanker accidents and things
14 like that, which we believe are very remote
15 concerns. But people live with those kinds of
16 fears. And, you know, hopefully they can be
17 overcome.

18 We think it's cost effective. We agree
19 with the -- I think he left -- who had all the
20 forecasts on the cost of LNG. We agree with those
21 range of costs, and we also agree that if you
22 bring LNG in from the South Pacific it'll cost
23 more, because of transportation costs you need
24 that many more tankers to keep that supply chain
25 going.

1 What can the state do to assure adequate
2 gas supplies in the future and to moderate prices,
3 California should promote the development
4 internally of gas supplies, pipeline facilities
5 and LNG receiving terminals in acceptable
6 locations. I don't know what's acceptable or not.
7 That's up to the people to decide.

8 And to enhance diversity of supply. You
9 make access available by having more pipelines and
10 so on. I think that's been stated by everybody
11 here.

12 We just don't know what that clearing
13 price will be. But, we do believe that LNG will
14 help put a lid on prices, as will development of
15 Alaskan gas and MacKenzie Delta. We do think
16 MacKenzie Delta is probably going to come in a
17 little later, maybe 2011 instead of 2010 because
18 there are so many issues to be resolved now with
19 native tribes exerting their rights and so on. So
20 there are quite a few delays there.

21 We think long term the price will be,
22 you know, on the \$5 to \$5.50 range in 2004
23 dollars. We're using --

24 PRESIDING MEMBER GEESMAN: Now, Herb,
25 your first bullet suggests that you expect prices

1 to remain high until LNG arrives. The staff price
2 projection showed prices declining by a couple of
3 dollars, if memory serves correctly, over the next
4 couple of years. Do you have a view on that?

5 MR. EMMRICH: Yeah, we have a similar
6 view.

7 PRESIDING MEMBER GEESMAN: Okay.

8 MR. EMMRICH: And my chart's coming up
9 in a couple of slides.

10 PRESIDING MEMBER GEESMAN: Okay.

11 MR. EMMRICH: Just the background here.
12 Again, there'll be development of these other
13 unconventional resources, and that will help keep
14 the domestic supply going. But we agree that the
15 conventional supplies are dropping very rapidly,
16 and it will be the unconventional that will help
17 to keep domestic production at least flat.

18 The problem is that demand overall is
19 growing very very rapidly. Like 5 percent a year
20 just on the electric generation market. And it's
21 just that gap that we need to fill with something
22 else. And we think LNG will help fill that gap.

23 In the long term there are other things
24 that can come online like clean burning coal. You
25 know, if that's environmentally acceptable and

1 gets some help, and that could reduce the demand
2 for power generation gas supplies.

3 So, as you see, in general that solid
4 blue line is our base forecast at the California
5 border. And you see where the staff's forecast
6 is.

7 The upper 90 percent is basically about
8 standard deviations above that. And the green
9 line is two standard deviations below. So, the
10 assumptions are what actually is going to happen.
11 And we're assuming that LNG will arrive in large
12 volumes and so on, but if that doesn't happen then
13 you're looking at a price that's hitting up to
14 that red line.

15 If more LNG shows up than you're
16 forecasting, because there are so many plants
17 under consideration, then you could hit more on
18 that bottom line.

19 Also, does the Alaskan gas show up
20 faster and the MacKenzie Delta, we don't know. So
21 you have a range of uncertainty. And that range
22 is fairly large.

23 The staff's forecast is gyrating around
24 that range. It's actually amazing that it stays
25 within the range over a ten-year period. But,

1 it's driven largely by the input assumptions on
2 when these additional resources will show up.

3 PRESIDING MEMBER GEESMAN: And you
4 suggested that you would move MacKenzie back a
5 year or so, and if I understood you correctly, put
6 the Alaskan resource at about the same time?

7 MR. EMMRICH: Yeah, around 2013, maybe
8 2014. Some people have even said 2016. But --

9 PRESIDING MEMBER GEESMAN: And that's
10 for Alaska?

11 MR. EMMRICH: For Alaska, yeah.

12 PRESIDING MEMBER GEESMAN: MacKenzie
13 about 2010?

14 MR. EMMRICH: Yeah, 2010, 2011.

15 PRESIDING MEMBER GEESMAN: Okay.

16 MR. EMMRICH: So we're not out of line
17 with those major assumptions.

18 PRESIDING MEMBER GEESMAN: Right.

19 MR. EMMRICH: I think we're more
20 optimistic on the LNG, especially in the Gulf
21 Coast, because they're moving forward fairly
22 rapidly, and there's not as much local opposition
23 because people there are used to major facilities
24 like petrochemical plants, refineries and so on,
25 the Houston area.

1 PRESIDING MEMBER GEESMAN: And would you
2 see the same result as the staff model suggests in
3 terms of pushing more production from the Permian
4 and Anadarko Basins west?

5 MR. EMMRICH: Well, that all depends on
6 how much LNG is going to arrive here on the west
7 coast. The assumption for the Semptra facility was
8 kind of low. But I think the staff was looking at
9 what hits California, not what is going to hit in
10 Mexico and California. Because the plant is
11 ultimately supposed to be sized at 1.2 bcf. The
12 first phase about 500 million a day and then maybe
13 two additional phases. And they're holding open
14 seasons now from what I understand.

15 And we've made no assumption of what's
16 happening at Long Beach or offshore Oxnard. But,
17 as you know, there are three facilities being
18 considered there. And --

19 PRESIDING MEMBER GEESMAN: You've made
20 no assumptions about the Chevron facility off
21 Baja?

22 MR. EMMRICH: No, we have not. We have
23 not. They have been going through the permitting
24 process. As far as I know they have all the
25 permits. I have not seen them sign any contracts

1 for deliveries, whereas Sempra did sign contracts
2 for deliveries to the Mexican Electric Generation
3 System. They have not signed any contracts that I
4 know of in the United States.

5 So, once that happens -- and there was
6 also some talk that maybe there would be a
7 combined facility. But I have no details on that.

8 PRESIDING MEMBER GEESMAN: Um-hum.

9 MR. EMMRICH: We actually, page 16, we
10 actually are looking at a study that we're working
11 on with CEC Staff and PG&E, and Southern
12 California Edison, to assess the impact of high
13 prices on the industrial sector and California, as
14 a whole. So we're going to have a consultant
15 prepare a study under the advisory committee
16 headed by the CEC. So make sure that we get a
17 unbiased view on what the possible impacts would
18 be on the California economy.

19 But we know from history that these are
20 major sectors that are affected, food and beverage
21 processors, paper producers, chemicals, stone,
22 clay and glass, and metals producers. And I think
23 PG&E said exactly the same thing. As prices are
24 high these people disappear totally into another
25 part of the world, or another part of the country.

1 What's the impact of high prices? And
2 we just gave a simple example. Just a few years
3 ago the price was about 40 cents a therm. It's
4 around 70 cents now. And that's \$1.5 billion just
5 for residential and small commercial customers per
6 year that California is shipping out. So anything
7 we can do to lower gas prices, of course, would be
8 a huge benefit to the California economy. And
9 this study will nail that down a little bit more
10 than just doing a simple example like this.

11 I'm open for questions.

12 PRESIDING MEMBER GEESMAN: Thanks very
13 much.

14 MR. EMMRICH: Thank you, again, for the
15 opportunity. We appreciate it.

16 MR. GOPAL: I believe Mark Meldgin
17 wanted to make some comments.

18 MR. MELDGIN: I thought I'd be following
19 my VP, Bob Howard, but he's out on something. I
20 have a few modeling issues, and I'll do my best to
21 be brief.

22 The first one, staff's gas price
23 forecast at the wellhead in a number of years
24 seems pretty high compared to the forecast that
25 PG&E gets from folks like the Cambridge Energy

1 Research Associates, PIRA, Wood-MacKenzie and so
2 on.

3 One reason seems to be this constrained
4 supply of LNG. We've talked about that some
5 before. But it would be interesting to see the
6 staff do a run where the switch that allows new
7 investment in LNG is turned on, just as the switch
8 to allow new drilling is already turned on in the
9 staff's case.

10 I should mention we actually run
11 MarketBuilder ourselves at PG&E. So, staff was
12 kind enough to send us their file and we could
13 open it and run it back at PG&E, and do some
14 tweaks with it. So that was very very helpful
15 that they were willing to send that to us.

16 The second one in the staff's forecast,
17 the difference between the gas price at the
18 wellhead and the gas price at the end user also
19 seems too high. And that comes from a staff
20 assumption that all gas flowing on a pipe from
21 point A to point B will be charged the full tariff
22 rate. And what we see in the market is that it's
23 routinely the case that pipelines discount.

24 So we've already talked to staff about
25 the idea of changing the inputs in MarketBuilder

1 in a way such that the price difference between
2 point A and point B is proportional to the flow
3 between point A and point B.

4 The third thing is the forecasted gas
5 demand by electric generators connected to the
6 PG&E system seems too high. That's in figure 15
7 on page 21 of the staff report.

8 In 2004 the generators and cogenerators
9 connected to PG&E burned about 860 million cubic
10 feet a day. And even that number is a bit
11 inflated because 2004 was a dry hydro year.

12 The staff's forecast for 2006 under
13 average hydro is 25 percent higher than our actual
14 in 2004, and higher again than what we would have
15 had in 2004 under average hydro.

16 I'm hopeful that if staff redoes the
17 allocation of that annual price into the 12-
18 monthly prices, that that will resolve this
19 problem quite a bit.

20 I should mention that PG&E also runs the
21 MarketSim model that the staff uses for electric
22 generation. And staff was kind enough to provide
23 us with that file, too. And we looked through
24 that and had a few minor quibbles, but nothing
25 like the things that we think are potentially

1 major problems in MarketBuilder.

2 And the last is the staff goes through a
3 process, and we have the deepest sympathy for
4 them, they go through this iterative process
5 between the electric simulation model to the gas
6 model, to the electric simulation model because
7 each time you get different gas prices you put it
8 in and you get different regional power point gas
9 demands, and you iterate and you go on and on and
10 on.

11 We've looked into that, and it's not
12 clear to us that there's any damper in that, so
13 that there's no guarantee that this iteration will
14 eventually converge. In particular in the
15 MarketSim model, the cost to move electricity from
16 point A to point B is fixed. It's not a function
17 of flow.

18 So, if from one case to another the gas
19 price for this combined cycle in Oregon all of a
20 sudden goes up by a nickel, there's a huge drop in
21 the power flows between Oregon and California.
22 So, we've recommended to staff that it might make
23 more sense to start with an estimate of gas
24 forecasts around the WECC based on historical
25 data, some growth projections. And then just go

1 through the cycle once.

2 That's all I had, thank you.

3 PRESIDING MEMBER GEESMAN: Thank you.

4 MR. GOPAL: Well, unless there are any
5 more questions, that brings us to a completion of
6 the phase one of today's process.

7 And now we will be talking about policy
8 issues and there will be presentations from
9 SoCalGas and PG&E. And back to you,
10 Commissioners.

11 COMMISSIONER BOYD: Well, now Dave gets
12 to start his lunch -- right-after-lunch
13 presentation.

14 MR. MAUL: Commissioner, do you want to
15 see if there are any comments either on the phone
16 or from the audience on the modeling session from
17 this morning before I start talking?

18 COMMISSIONER BOYD: I think that would
19 be appropriate.

20 MR. MAUL: Do we have any comments --

21 COMMISSIONER BOYD: Is there anybody out
22 there on the telephone who would like to comment
23 on what's transpired so far? Nobody in the
24 audience has so volunteered. I don't know if you
25 have an audience out there.

1 (Pause.)

2 MR. MAUL: Thank you, Commissioners.

3 For this afternoon's presentation, we'll hopefully
4 be through here in the next hour with all the
5 various parties' comments on this. I'll make mine
6 fairly brief.

7 But I wanted to go through and provide
8 you a sense of all the modeling, the technical
9 information that you got this morning, and what
10 we've looked as far as examining the natural gas
11 markets over the last couple of years, the market
12 behavior, operations issues in North America and
13 the west and California.

14 Where prices are going, demand is going,
15 and to finally get some sense for all of that in
16 kind of one comprehensive overview. And then
17 basically trying to focus this back to California.
18 What can Californians do, what can you do as
19 policymakers, and the state of California do as
20 policymakers, as far as decisions.

21 And we've laid out a series of questions
22 that we think are appropriate to examine, provide
23 some answers to. Some you might get answers to
24 today. I think we'll get some more answers over
25 the next few weeks to a few months in studies that

1 we are currently doing that will provide more
2 information back to you. And that the parties are
3 also doing, as we go on.

4 But I'd like to just go through very
5 quickly a series of just kind of quick overview
6 here, kind of tee up a number of policy questions
7 that we think the Commission needs to address, at
8 least some of these, not all of them, at this
9 current cycle. But most need to be addressed here
10 in the next few years, hopefully as many as we can
11 in this upcoming IEPR cycle.

12 Let me just quickly go through the goal
13 that we have to give you some more quick context,
14 because a lot of folks know gas, but some folks
15 that don't know gas well enough need a little bit
16 more context on how we make our decisions.

17 The theme that we're looking at this
18 year versus past years, and finally the issue
19 categories that we'd like to look at with various
20 questions.

21 Our policy goal, as we wrote in the
22 report, really is to insure a reliable supply just
23 to meet demand. It's not to have excess or too
24 much excess supply. But we want to make sure that
25 demand and supply are balanced with enough excess

1 supply to make sure that we have reasonable prices
2 and have some mechanisms in to provide stability
3 to prices, so consumers of all categories, whether
4 it's you and I as homeowners, our water heaters
5 and our cooking, or where there's an industrial
6 process or a commercial building can have some
7 confidence in forecasting what their budgets are
8 going to be in the price area.

9 Also we have to take into account in our
10 choices environmental impacts, making sure that we
11 pick choices that not only don't harm the
12 environment, but also possibly help the
13 environment, as well.

14 And all within that, looking at market
15 risk, and the various parties and participants in
16 the natural gas area, what they can do to help
17 manage the risk.

18 We look at it more from an
19 infrastructure physical risk management
20 perspective; but obviously there's a lot of
21 parties who looks at it from a financial risk
22 management perspective, as well.

23 The context, general context still is a
24 kind of overview of what you've heard here this
25 morning is that the national demand for natural

1 gas still is growing. California natural gas is
2 growing, but at much lower rates, though it's
3 still growing very slightly. So we're actually in
4 relatively good shape from that perspective. It's
5 been a real success story over the last 20 years
6 with our energy efficiency programs and our
7 renewable programs that are now emerging to have
8 an effect on reducing the demand for California.

9 PRESIDING MEMBER GEESMAN: I want to
10 make certain that when you say that on your second
11 bullet, I'm clear that you're saying it both with
12 respect to electricity generation demand, as well
13 as nonelectricity generation demand.

14 MR. MAUL: Yeah, I look at the overall
15 gas demand, the entire -- everything inside the
16 state border, all sectors at once, because it's
17 really the entire flow regardless of what sector
18 it goes to, figure it's really determined for the
19 overall need for infrastructure, which is our
20 focus. It is important to differentiate between
21 the various sectors of electricity versus
22 nonelectricity, for example, on some of the sub-
23 issues that we get into. And I'll cover that in a
24 minute.

25 PRESIDING MEMBER GEESMAN: Right. Some

1 of our supporting documents in the '03 cycle were
2 a little ambiguous when we made those conclusions
3 as to whether it encompassed 100 percent of
4 demand, or just the nongenerating portion of
5 demand. But I understand your comment to
6 encompass 100 percent.

7 MR. MAUL: Yes, that's correct. Yeah.

8 And just as a quick reminder for folks
9 that don't know gas that well, the weather really
10 is the biggest driver in variation in demand
11 month-by-month, day-by-day and even year-by-year.
12 And we really have very little ability to predict
13 weather on a long-term basis. Can predict it much
14 more than three days out, much less five years
15 out.

16 Also, on the supply side it's very
17 clear, looking back historically and also looking
18 at projections, that U.S. supply growth in natural
19 gas is not going to be able to keep up with U.S.
20 demand in growth. There's a growing gap. That
21 gap will be filled by LNG and other imports from
22 Canada over the next coming decades. And so
23 California has long seen that picture because we
24 import over 85 percent of our natural gas right
25 now.

1 New supplies, as you've heard from our
2 model, are becoming riskier to get. We're looking
3 in there, talking actively now about
4 unconventional resources and the cost to bring
5 those in is higher. Whether we can bring them in
6 because of more restrictions. And whether we want
7 to push that issue or not. There's a lot more
8 risk on the supply side than we have historically
9 seen, both on just getting physical supplies, as
10 well as the price for those supplies.

11 And also it's important to point out
12 that the supply to California is also affected by
13 demand outside of California. And there were some
14 brief statements earlier this morning about that.

15 But, for example, if there is an extreme
16 heat storm say in the Phoenix/Las Vegas area, then
17 the supply reliability to California is degraded.
18 Because even though there's pipe there, they will
19 take gas out to feed electricity. Or on the other
20 hand, if there is extreme cold in the Northwest
21 they will take gas out of the pipe to heat their
22 homes there before it gets down to our area.

23 So we are at some risk even on the
24 supply side just because of the areas we transport
25 our gas through. And it's important that we take

1 that into account. One reason why, we do like
2 instate storage as much as we do is that buffer
3 against that physical risk we have to put up with.

4 And also we heard this morning
5 California, we believe, really has adequate
6 infrastructure, that is pipe infrastructure, to
7 import gas on an annual average basis. We have
8 not examined the peak day or the extreme peak day
9 yet. We're doing only the long-term forecast for
10 today. And we need to go back and re-examine
11 that. And that is under active discussion at the
12 PUC. We're working with our colleagues there, as
13 well as re-examining that issue, ourselves, to try
14 to figure out what is that extreme peak day; what
15 does it look like; and do we have adequate
16 supplies and infrastructure to meet that extreme
17 peak day. But that is not something that we can
18 address today for you.

19 As I mentioned already, there may be
20 some opportunities for instate infrastructure,
21 whether it's additional pipe to relieve some
22 congestion deliverability issues. For example,
23 just last November we saw the San Diego area
24 unexpectedly having a near crisis that was avoided
25 within a few hours because they had some problems

1 at a pipeline supplying that area. They were able
2 to activate the line, the TGN line, that comes
3 directly from Tijuana back up to San Diego, at the
4 last minute to allow gas to flow to help solve the
5 problem in San Diego.

6 But it would be nice to have
7 infrastructure inside California to avoid those
8 kind of problems in the future. It's not ones
9 that we can forecast very well, but there may be
10 some opportunities as we get further into the
11 details and subregions of the various areas of
12 California.

13 And finally, instate storage, additional
14 storage, may be desirable from both a physical and
15 a financial risk management tool.

16 PRESIDING MEMBER GEESMAN: I want to
17 better understand the top bullet there, and what
18 it is you're actually saying. That means we have
19 adequate interstate pipeline capacity to import
20 additional natural gas, in your judgment?

21 MR. MAUL: Yes, we do, as far as the
22 pipe diameter capacity to bring gas supplies in on
23 an average annual basis, we can flow enough gas
24 over the course of the year to meet the annual
25 average demand inside the State of California,

1 plus the production in California.

2 COMMISSIONER BOYD: To the border or
3 throughout the state, as well?

4 MR. MAUL: We have not examined
5 throughout the state because our model tends to
6 look more on a gross basis coming to the state.
7 We don't have the detailed distribution system
8 model that the utilities have. And so there may
9 be some regional congestion issues that we're not
10 aware of at this point in time.

11 PRESIDING MEMBER GEESMAN: And is that
12 annual average the appropriate way to look at it?
13 Or these seasonal flows subject to peak loading
14 conditions?

15 MR. MAUL: Well, that's what I just
16 mentioned a minute ago, and that we would like to
17 get down to a monthly forecast and look at the
18 peak demand during the month to see whether we can
19 still meet that peak demand or not.

20 Right now, because we have excess
21 capacity on the pipelines, and we have excess
22 capacity in our storage system, over an average
23 annual basis, we're comfortable that we can meet
24 the peak. We have increased our interstate
25 pipeline capacity and our instate storage capacity

1 significantly over the last three years. So we're
2 in actually much better shape today than we were
3 three years ago. Infrastructure increases have
4 outpaced demand increases, so we're more
5 comfortable today than we were three years ago.

6 I still can't answer the question for
7 you whether we have the extreme peak day of say
8 the cold weather that we experienced back in 1932
9 where we had snow in Los Angeles. If that same
10 weather pattern were to happen today, would we be
11 able to meet that peak demand day today. That's
12 an open question. We're debating that actively.
13 We don't have an answer for you in that one.

14 And it may be that we decide as a larger
15 community of natural gas participants, that is the
16 utilities, PUC, ourselves and the customers, that
17 it just may not be worthwhile trying to build
18 enough capacity to meet that highly unusual event.
19 We just get ready to plan for it.

20 There are other strategies we can look
21 at. On the gas side, for example, there are the
22 equivalent of demand response strategies,
23 interruptible contract strategies where there are
24 certain end users we may identify as having
25 alternative supplies. And I'll get to that in

1 just a minute later in my slides here.

2 PRESIDING MEMBER GEESMAN: And when you
3 say we have adequate infrastructure to import
4 natural gas, we don't have any LNG import
5 capability right now.

6 MR. MAUL: In California that's true,
7 and we don't assume any in our model here.

8 PRESIDING MEMBER GEESMAN: Okay. I
9 guess I'm not clear what constitutes adequate.
10 Adequate infrastructure to import an adequate
11 quantity of natural gas? Or --

12 MR. MAUL: Looking at the average annual
13 demand, taking up the entire year and adding up
14 all the demand for all the molecules, do we have
15 the ability to transport those molecules across
16 the pipes for that entire year.

17 With the storage system we have, we
18 don't have to have, as we did in the electricity
19 side where you have to have immediate demand
20 response and supply matching every second of the
21 day, because we have such a large storage capacity
22 inside the State of California, we're able to
23 bring supplies in more on an average basis and
24 allow storage to be the swing supplier inside our
25 state as demand goes up and down at a more

1 volatile basis than say the supplies might come in
2 under a baseload basis.

3 Obviously supplies do come in on a
4 cyclic basis. We track pipe utilization on a
5 monthly basis here for California. Understand
6 that, you know, the flow (inaudible) a pipe, we
7 tracked that back for a number of years and you'll
8 find that the pipe utilization curves are much
9 more dampened, they're much more moderate compared
10 to the actual sendouts by the utilities.

11 And they simply use, if demand inside
12 the state is less than the flowing gas coming
13 across, they'll just store the extra underground.
14 If demand is greater they'll pull storage out of
15 ground and supply the end use customers.

16 PRESIDING MEMBER GEESMAN: But do you
17 think that both additional instate pipe and
18 additional storage may be desirable?

19 MR. MAUL: Maybe, and that's because we
20 don't do the seasonal evaluation I can't give you
21 a definitive answer that we definitely need more
22 storage today or we definitely need more pipe
23 today. But it appears, based on our experience
24 looking back the last several years, that there
25 may be opportunities to do intrastate pipes to

1 relieve some congestion issues.

2 And also in the intrastate storage
3 issues, we are looking at storage for California
4 inside the State of California, and we're also
5 even looking at storage in California for other
6 state's markets.

7 For example, I mentioned earlier that
8 our reliability of supply is threatened by the
9 demand outside the State of California. And we've
10 been talking to folks in Arizona about them
11 developing more storage, having storage in Phoenix
12 where there is none right now, would help their
13 reliability of their supply. And also increase
14 the reliability of our supply.

15 If they fail to develop any kind of
16 storage in Phoenix, and we need to examine whether
17 we can build storage in California to meet a
18 Phoenix market, and that logistically works out
19 well, we can explore that as a very good concept.

20 PRESIDING MEMBER GEESMAN: Okay.

21 MS. JONES: Dave, can I ask an
22 additional question on the pipeline capacity.
23 Bill had up the slide earlier that showed the
24 capacity utilization on the different pipelines.

25 And we talked earlier about the TGN line

1 being used at 125 percent of capacity from '08
2 forward through the forecast period.

3 If you don't add any additional pipeline
4 capacity can you really say that the pipe is
5 adequate?

6 MR. MAUL: Yeah, the TGN line, I think,
7 is 174 mcf per day; looking at 10 percent over
8 that would be 17 mcf per day. If I compare that
9 to say the El Paso north or south pipelines, which
10 were 1000 mcf per day, there's a lot of extra room
11 on the El Paso north and south lines, as well as
12 the lines from the north, the GTN lines.

13 So we're only looking at 10 mcf per day
14 difference between 100 percent utilization and 110
15 percent utilization on that TGN line.

16 MS. JONES: So you're looking at it from
17 a very general perspective of adding up all the
18 receipt points, --

19 MR. MAUL: Yes.

20 MS. JONES: -- not necessarily
21 allocating them by region.

22 MR. MAUL: Yes. We have reasonable
23 ability to ship gas around the state north and
24 south. For example, the line 1903 that's
25 currently proposed by El Paso would help in

1 intrastate flexibility to move gas better back and
2 forth is one more example of lines that we expect
3 to come online here soon.

4 COMMISSIONER BOYD: Dave, I just want to
5 comment on your first bullet. You've explained
6 what you meant by that, but the uninitiated,
7 unwashed might assume that we already have LNG
8 import location facilities in California. So, --

9 MR. MAUL: Yeah, we have none right now
10 and the model does not assume any new import
11 terminals inside the State of California. It only
12 assumes on the west coast the Baja facility
13 proposed by Sempra.

14 Also it's been real clear that prices
15 have increased dramatically recently. They also
16 are much more volatile now than they used to be.
17 There's a variety of reasons for that. Mike
18 Purcell, in his supply discussion this morning,
19 talked about the drilling problem.

20 What we've looked at is actually the
21 capability of U.S. wells to produce gas on a daily
22 basis versus a demand. And for many decades
23 through the '70s, '80s, and even into the early
24 '90s, every time there was an increase in demand
25 over daily or a weekly basis, there was a lot of

1 excess production capacity of all the wells in the
2 U.S. They simply turned on the valves larger and
3 more gas flowed.

4 Since about '95, '96 we've lost that
5 excess capacity to actually open the valves more.
6 Most wells now in the U.S. operate at greater than
7 90 percent capacity. So you're basically flowing
8 gas as fast as you can out of the ground.
9 Therefore, you've lost your shock absorber effect
10 or capability out of the well system. You have to
11 look to someplace else to get that.

12 Because of that there is less shock
13 absorber ability and now we're seeing much more
14 volatility as demand suddenly goes up from either
15 a cold front going through, or a heat storm coming
16 through. There's less ability on the supply side
17 to respond to changes in the demand. Therefore,
18 we see much more volatility in the price as a
19 result from that.

20 And then finally one thing that I think
21 most folks here in the room, but maybe others
22 might not fully understand, is that we are fully
23 connected to the North American market because of
24 our pipes and because we've been importing gas for
25 so long. Therefore, we really have to track

1 what's going on elsewhere in the U.S. from not
2 only the supply side, but also the demand side.

3 If there's a hiccough in weather in the
4 northeast, or in Texas, it does affect prices in
5 California. And we all basically are off a single
6 benchmark, Henry Hub, as mentioned before. Prices
7 are tagged back to that. There's a price
8 differential. Either we pay more or less than
9 that, but that is the benchmark. And everything
10 flows back to that same benchmark.

11 And so we've seen a number of times
12 where there's been a heat storm, or more
13 particularly a cold storm in the northeast causing
14 prices to spike wildly. As we mentioned we're
15 paying \$4 to \$5 per unit for natural gas. At one
16 point in the northeast a year and a half ago, they
17 were paying \$70 for the same unit of natural gas.
18 Fortunately, there were only a few trades at that
19 level. But those high prices dragged our prices
20 up much higher, even at the same time that our
21 demand in California did not change very much at
22 all. It was very moderate at the time.

23 So we're very sensitive to the price
24 situation. And we have to be aware of what we
25 might do in California versus what is expected

1 versus what might go on elsewhere in the U.S. that
2 be even more effective.

3 With all that context, basically our
4 theme is because we believe the infrastructure is
5 in much better shape now than it was before, we
6 need to really focus on the price issue and what
7 actions we can take in the price area.

8 PRESIDING MEMBER GEESMAN: I guess I'm
9 continuing to have a problem on this
10 infrastructure statement. Maybe it's embedded in
11 the report, but I haven't seen it in the
12 presentations that establishes an adequacy. And
13 I'm trying to determine what it is I'm missing --

14 MR. MAUL: Well, I think the charts that
15 Bill Wood provided on infrastructure and the
16 chapter on infrastructure shows that we basically
17 have enough interstate capacity now, what's
18 expected to come online here in the near future,
19 to take care of our needs through 2016, the
20 forecast period. That our demand is not growing
21 very fast. And we do have excess capacity on
22 those particular pipelines, so we can import
23 enough gas during that timeframe to fill those
24 pipes up. We do a little bit of excess capacity
25 on a few of them and their utilization factor

1 should back and forth.

2 But from that perspective we don't see
3 the need to build a brand new interstate gas
4 pipeline or do a major expansion of an interstate
5 pipeline.

6 PRESIDING MEMBER GEESMAN: Your model
7 was showing 125 percent on I believe it was El
8 Paso south?

9 MR. MAUL: No, that was on the TGN line
10 which goes directly from Baja up north. It's a
11 very small line.

12 PRESIDING MEMBER GEESMAN: Yeah, what
13 were you showing on El Paso?

14 MR. MAUL: Well, El Paso we go from
15 what, 40, 50 percent up to about 90 percent.
16 Bill, did I get the right number, 90 percent?

17 MR. WOOD: Let's step back for just a
18 second. If you remember one of my charts that
19 indicated that the interstate supply is running at
20 around 5500 million cubic feet per day. And then
21 if you go back one slide we show the interstate
22 capacity to receive is in the area of about 8
23 billion cubic feet per day.

24 So the differential between 8 billion
25 and 5.5 billion is what we're considering to be

1 slack capacity that is adequate to meet adverse
2 swings.

3 With regards to El Paso south I
4 indicated that we're looking at about 155 percent
5 of the main line capacity indicating that we would
6 have to have new capacity added to that particular
7 pipeline. That is not to meet California
8 requirements; that's to meet east of California
9 requirements.

10 Our receiving capacity at the border
11 were in the area of 80 -- I don't even remember
12 the numbers now -- I'll have to look and see here.
13 I don't have those notes with me. But they were
14 considerably less than 100 percent at the
15 California border at Topoc and at Blythe.

16 PRESIDING MEMBER GEESMAN: Okay.

17 MR. WOOD: So, and then again, Kern
18 River, and we showed Kern River running at 100
19 percent or 95 percent capacity, no additional
20 requirements there. And then GTN was running
21 considerably below capacity, but we think that
22 that needs to be looked at closer as a result of
23 some changes that we need to make in northern
24 California production.

25 MS. JONES: Can I ask a question? When

1 you talk about pipeline capacity and you talk
2 about slack capacity, you're looking at the total
3 receipt points. But isn't it true that the slack
4 capacity really relates to an individual pipeline.
5 And that when you start loading up the lines
6 higher you see prices start to spike?

7 So have you -- I'm just wondering if you
8 have not just lumped everything together so that
9 you don't see that there might be an additional
10 value for slack capacity on some of the individual
11 lines by looking at receipt points for the whole
12 state.

13 MR. WOOD: To get into that sort of
14 thing we'd have to get into seasonality, a look-
15 see. Because on an average annual basis you don't
16 see it.

17 PRESIDING MEMBER GEESMAN: Well, and
18 that's why I'm asking that we avoid the sweeping
19 generalizations until we get into some of those
20 areas. My concern is the potential misuse of a
21 bullet statement such as infrastructure appears
22 adequate for now, when I think what you've been
23 talking about is interstate pipeline
24 infrastructure, and even that generalization might
25 be undermined by a closer look at seasonal

1 concerns.

2 MR. WOOD: Okay.

3 MR. MAUL: Yeah, I think that's an
4 accurate characterization of the report.

5 PRESIDING MEMBER GEESMAN: Okay.

6 MR. MAUL: Okay, as far as the issues.
7 Let me go through some quick issue categories
8 here. We've got four or five of them, but as far
9 as the issues --

10 PRESIDING MEMBER GEESMAN: Dave, before
11 you got that, I wanted to give Wendy a chance to
12 ask another question.

13 MS. PHELPS: Thank you. Let's see, I
14 was just wondering, the EIA 2004 California
15 natural gas consumption data shows a 10 percent
16 increase from the 2003 annual consumption data.

17 So with that, how comfortable are you in
18 still saying that there's only a slight increase
19 in demand for California?

20 MR. MAUL: Well, we're looking at long-
21 term, and go back a number of years to going out
22 the next ten years. So, the forecast perspective,
23 we're only looking at a 1 percent or slightly less
24 than 1 percent demand growth year by year.

25 If you look at any individual year you

1 have to take in the varied weather and also the
2 effect in the last couple of years of the
3 increased number and use of more efficient power
4 plants where we actually saw consumption drop,
5 historical consumption drop because of the greater
6 use of more efficient power plants providing the
7 same electricity with less gas consumed.

8 We're now getting through that bulge,
9 and we're kind of back up to it again. Our last
10 report, and I think our historical number we had
11 in the chart showed that there was that drop, dip
12 at about 2002, 2003. And we're coming back up
13 from that now.

14 MS. PHELPS: But, I guess if there
15 really was that much of a jump, you know, just
16 this last year, would that -- could that affect
17 the future forecast, too?

18 MR. MAUL: I don't think we're even
19 getting back up to the 2001 demand level --

20 MS. PHELPS: And I think -- I think it's
21 close --

22 MR. GOPAL: From 2001 what happened was
23 there was a very big drop in 2002 and we are still
24 trying to catch up with normal demand in the '3
25 and '4 time period. So it's really not firm

1 indication that future demand is going to grow at
2 that same pace.

3 MS. PHELPS: Okay, well, I mean it
4 looked like it was close when I looked at the EIA
5 data recently, that we've gotten close to the 2000
6 and 2001 consumption.

7 MR. MAUL: We're getting back close to
8 that again, but we don't think that we're going to
9 see that same growth rate just in the last two
10 years. We have to take a longer term perspective
11 and consider other factors than just a couple
12 years which are affected by weather more than
13 anything else.

14 MS. PHELPS: Okay, thanks.

15 MR. MAUL: Okay, the issue categories
16 that we think need to be addressed. In the demand
17 area we obviously like energy efficiency. As a
18 gas guy the more energy efficiency programs that
19 my colleagues do in our Commission, as well as at
20 the PUC, as well as the utilities, makes our job
21 easier.

22 But the question is how far can we push
23 that. Energy efficiency is our top priority here
24 at the Commission for the State of California. We
25 think it has a very beneficial effect for

1 consumers, which is our priority.

2 And we can push the energy efficiency
3 programs ever farther than we have already. If we
4 were to do more energy efficiency programs in the
5 various categories of electric generation,
6 consumer, commercial, industrial and residential,
7 can you get much more out of the system because
8 we're pushing it so far and so aggressively
9 already.

10 And we we'd like to see if we can answer
11 the question can we get more above and beyond
12 what's already been assumed in the model or
13 assumed in the programs we have so far.

14 Within that there's certain
15 subcategories that staff would like to see
16 addressed, whether, for example, in the
17 residential whether the solar water heating now is
18 becoming more cost effective, and whether it'll be
19 used more in the future. It hasn't been used much
20 in the past, but whether there's a possibility in
21 the future.

22 Commercial, whether there's better
23 opportunities for building and appliance
24 efficiency standards in the commercial area. And
25 in the industrial there's a lot of industrial

1 energy efficiency programs that might be possible,
2 as well.

3 So the same issue goes with renewables.
4 If you develop greater renewables, whether it's
5 wind, biomass, they do save gas. Wind, for
6 example, might not have much effect as far as peak
7 electricity capacity, but every time the windmill
8 turns it does provide electricity, and because
9 gas-fueled power plants are the swing power plant
10 in California to be dispatched, more electricity
11 from any resource reduces electricity fueled by
12 gas. So it's a benefit to the gas side.

13 And finally, the last issue in the
14 demand area is should we go back and re-examine
15 the ability to fuel switch inside California.
16 Obviously fuel switching has been looked upon very
17 poorly because of the air quality considerations,
18 and we supported that.

19 But we've been talking to the Air
20 Resources Board Staff to see whether there are
21 opportunities to develop clean fuels that could be
22 used in the event that we start to get close to an
23 emergency, or even start considering economic
24 benefits to fuel switch, as long as there's clean
25 fuels and there's not a significant air quality

1 benefit.

2 The economic issue is a more difficult
3 one, but from the emergency perspective our
4 colleagues at the Air Resources Board are quite
5 concerned about having a gas curtailment which
6 would cause an electric blackout, which would then
7 trigger backup generators burning a dirty fuel,
8 diesel, in older generators and the air pollution
9 from that. So we're trying to do a tradeoff
10 between some scenarios of electric -- gas
11 curtailments going to electric blackouts versus in
12 advance trying to forestop that with clean fuel
13 switchout.

14 COMMISSIONER BOYD: What does clean fuel
15 mean, though, in this context?

16 MR. MAUL: Clean fuel could be
17 additional natural gas storage on a micro basis.
18 You have LNG stored, trucked in and stored at or
19 near a power plant location with a very small
20 amount of fuel. It could be propane. It could be
21 methanol, ethanol.

22 Most of our newer turbines were not
23 built for dual fuel, but they could be retrofitted
24 to go with clean fuel, dual fuel. But we're not
25 considering either diesel or distillate for

1 California. It's just, I think, an inappropriate
2 fuel choice for the state.

3 PRESIDING MEMBER GEESMAN: So what would
4 that scenario look like?

5 MR. MAUL: Well, the scenario might be
6 that if we get close to, in the wintertime, a gas
7 curtailment because of unexpected demand, and we
8 had either a regional or statewide gas
9 curtailment, we don't predict a statewide gas
10 curtailment, but there are possibilities for a
11 regional gas curtailment, much like we almost saw
12 down in San Diego last November.

13 If we had a few selected power plants
14 that had dual fuel capability with a clean fuel,
15 then you could, in advance, ask them to switch
16 fuel, dropping gas demand quickly and preserving
17 your residential and commercial and other
18 industrial customers that keep them online.

19 The example we saw just last November
20 was actually switching fuel to a dirty fuel in the
21 San Diego area. They still have a couple power
22 plants that are fueled with fuel oil. And they
23 were able to switch for a few hours to relieve the
24 pressure off the pipes and allow things to catch
25 up. But we'd like, if we get to that situation

1 again, we'd like to be able to switch to a cleaner
2 fuel and not fuel oil.

3 Okay, the issues we'd like to see
4 addressed on the supply side, first changes in the
5 natural gas quality and for the supply. We're
6 currently working with the Air Resources Board,
7 our colleagues at the California Public Utilities
8 Commission, and other folks to look at the natural
9 gas quality issue.

10 I'd like to note that we have -- no, we
11 don't have, but the Air Resources Board has a
12 technical workshop noticed for August 3rd on this
13 issue to look at a change in the natural gas
14 vehicle specification for gas quality that might
15 make some changes to allow a little more gas to be
16 produced inside our state, or to get to our state,
17 imported the LNG indirectly from other areas.

18 We are working with them; that's being
19 done in conjunction with the CEC Staff. And so
20 we're all trying to work as a working group to
21 figure out what can we do to make a change to get
22 rid of gas supply through a change in the quality
23 specifications that does not significantly harm
24 air quality. That's our absolute cutoff there.
25 So we can't propose anything that will cause a

1 change in air quality.

2 Also is there anything we can do to help
3 increase natural gas production. We had formed a
4 working group of the industry on the permitting
5 process to try to accelerate a streamlined
6 permitting process and made some good progress
7 there.

8 The industry was appreciative of it.
9 But we still don't see increase, a significant
10 increase in the number of permits being pulled
11 today on a monthly basis here for drilling in
12 California.

13 The question is can more be done to
14 increase California production. And as much as
15 industry is trying to respond to the price issue,
16 we just don't see gas production in California
17 increasing significantly.

18 It may, because of lag time there may be
19 greater increases with the increases in prices
20 we've seen in the last couple years. But, we were
21 hopeful that we would have seen those demand -- or
22 those supply responses because of the higher
23 prices by now. We just haven't seen it as of yet.

24 The third bullet is on alternative
25 natural gas supplies. Because of the new R&D

1 opportunity we have and the funds that this
2 Commission administers, working with the CPUC,
3 we'd like to focus some of those funds on
4 development of alternative gas supplies.

5 Whether we can explore biogas
6 development, other kinds of gas. We can actually
7 create gas from other resources to enhance and
8 augment the gas supply that we currently have
9 inside the state. Anything to diversify our
10 supply source I think would be beneficial as long
11 as it's cost effective.

12 So we're exploring the possibilities of
13 biogas as well as using R&D, targeted R&D, to help
14 in that area.

15 PRESIDING MEMBER GEESMAN: Pipeline
16 quality.

17 MR. MAUL: Pipeline quality. Well, I
18 will qualify that. Generally pipeline quality, if
19 the gas is put into the state's pipeline system.
20 We also need to examine whether there are
21 opportunities to have locally used gas where
22 quality doesn't matter.

23 For example, taking a very small
24 generator and dragging it to the wellhead, or if
25 you take a few wellheads and manifold them

1 together. So therefore the gas is brought out of
2 the ground and used in a productive and efficient
3 manner, but it's never put into the pipeline
4 system. But the state still gains the benefit of
5 the energy that comes out of the ground, that is
6 then converted there locally. So that are areas
7 we need to explore, as well.

8 Finally, also does LNG have enough
9 benefits to outweigh its potential costs. This
10 has been a controversial issue so far. We are
11 examining it from a molecule perspective, price
12 perspective. We don't get into the licensing and
13 siting issues in this report, so we don't really
14 have any judgment on the potential costs of LNG
15 from a siting or community perspective.

16 We do provide some insight on LNG from a
17 molecule and price perspective.

18 PRESIDING MEMBER GEESMAN: So, what's
19 changed since our 2003 report when the Commission,
20 I think, said pretty clearly the answer to that
21 question is yes?

22 MR. MAUL: From a price perspective,
23 you're right. We believe that there's a price
24 benefit by having more LNG supply come to the U.S.
25 and come to the west coast. In IEPR 2003 we said

1 we encourage LNG coming to the west coast. It
2 could be Baja, California, it could be Oregon.

3 Now the question is do we want to look
4 at LNG coming directly to California. And is
5 there enough price benefit to have a terminal
6 located in California, or are we satisfied with a
7 terminal located in Baja.

8 PRESIDING MEMBER GEESMAN: How do you
9 end up being able to address that question without
10 getting into some very site-specific and project-
11 specific issues that we have no jurisdiction over?

12 MR. MAUL: We can get into -- well, you
13 basically do an assumption with the model that you
14 assume a site can be found and can be permitted
15 successfully with acceptable environmental
16 impacts, just as you do for power plants or
17 transmission lines in the future.

18 The model looks at it from an economic
19 perspective, but does not make any judgment from a
20 social or community perspective.

21 So, obviously, just as we would look at
22 transmission lines or power plants, assuming we
23 need more of them, saying you need more
24 transmission lines assumes you can find a
25 transmission line corridor or route that's

1 acceptable, as well.

2 But we're not --

3 COMMISSIONER BOYD: I share Commissioner
4 Geesman's concern with that statement. In fact, I
5 have concern with the tone or the wording of a lot
6 of these statements.

7 But in the 2003 IEPR and subsequently we
8 have said LNG is good for California if it's sited
9 to meet all environmental concerns, et cetera, et
10 cetera, et cetera. And this sounds like, you
11 know, we're going back on that a little bit.

12 It's just like the first bullet. Will
13 changes in natural gas quality improve supply. I
14 think we launched on that question several years
15 ago, with the answer already known. Yes. We have
16 domestic supplies that get shut in. If you can
17 use them that's going to increase the supply.

18 So I hear what you say to explain the
19 bullets in response to questions, but I think
20 perhaps a little careless in the wording of some
21 of the bullets.

22 But the LNG one has -- that statement
23 has policy ramifications, as Commissioner Geesman
24 properly identified. I don't think that's -- we
25 should consider the wording a little more

1 appropriately.

2 MR. MAUL: Okay.

3 PRESIDING MEMBER GEESMAN: Yeah, I
4 recognize that one of the charms of government is
5 that nothing ever gets finally resolved. But I
6 think that we would be well advised to stand on
7 the shoulders of the giants that preceded us in
8 the 2003 IEPR cycle. And take the pronouncements
9 from that report as still current and applicable
10 expressions of Commission policy.

11 MR. MAUL: Yes, we definitely support
12 the 2003 IEPR as a Commission policy.

13 Okay, our last bullet is kind of a
14 summary of everything else above it. On the
15 supply side, will increased supply diversity lower
16 prices. We believe it will. We're going to be
17 doing a study to see how that might lower prices.
18 So, how much of a price effect you get.

19 On the infrastructure side we're looking
20 at slack capacity, that is reserve margin, gas
21 equivalent to reserve margin electricity side.
22 And there's been the standard way of looking at
23 slack capacity for a number of years. We need to
24 re-examine whether that way of determining slack
25 capacity is still an appropriate way to do it,

1 given the realities we have of the market prices
2 and the volatility that we have today.

3 And so we'd like to work with our
4 colleagues in the CPUC to see whether the way
5 slack capacity is defined and determined should be
6 modified to reflect current market conditions
7 instead of the past issues.

8 We all seem to look at intrastate
9 infrastructure to see whether we need to improve
10 what I call deliverability. That is, relieving
11 congestion issues inside the state. Our model
12 doesn't get into it in as much detail as we'd
13 like, so we have to do some outside analysis to
14 look at the deliverability issues.

15 Also we think more storage is needed and
16 desirable. How much more is a question we have to
17 define from our modeling perspective. We do have
18 some work underway with a UCDavis consultant,
19 looking at how one might use storage from an
20 economic perspective. In the past it's only been
21 used from a reliability perspective. And we
22 believe there's additional value to look at
23 storage from an economic perspective.

24 There is some question about LNG
25 terminals and whether we should continue to model

1 an LNG terminal equivalent to a piece of pipe.
2 Whether it actually would function the same way
3 from a reliability perspective, deliverability
4 perspective. And we got into that a bit at the
5 June 1st and 2nd LNG access workshop we held here
6 under the IEPR auspices. No, it was not IEPR
7 auspices, it was the Resources Agency auspices.

8 And finally, can California help to
9 improve out-of-state storage needs. I already
10 mentioned Phoenix, the southwest area. We have
11 some similar concerns about the northwest areas,
12 Oregon and Washington. When they have extreme
13 demand in the wintertime, and their demand goes up
14 dramatically, they just pull off the pipe. They
15 have very limited storage up there, which again
16 threatens reliability of the flows through the
17 pipe that we already have coming down from the
18 north.

19 In the market area --

20 MR. SMITH: Dave, --

21 MR. MAUL: Yeah.

22 MR. SMITH: -- before you leave that
23 slide, the bullet on storage. The interplay
24 between storage and pipeline capacity is obviously
25 becoming more and more critical in terms of being

1 able to meet peak demands.

2 Do we know -- do we understand the
3 drivers in the storage market that provide
4 incentives for either, I guess in this case
5 privately owned storage. Do we know enough about
6 that to talk in a more informed manner in the 05
7 IEPR about what it would take to get more storage
8 in place? What it would take to provide
9 incentives to private storage operators?

10 A corollary question is what's the --
11 how much storage is privately owned and how much
12 is utility owned?

13 MR. MAUL: Yeah, we have two kinds of
14 storage here in California. We've got utility-
15 owned storage, which has been developed for
16 reliability purposes, and the CPUC has set out
17 guidelines on how that is to be filled and
18 maintained over the course of the year; how much
19 capacity is needed and how many molecules should
20 be inside that capacity by certain time periods
21 over the year to meet our peak heating season.

22 So in that case that, which is the bulk
23 of the storage in California, that is driven by
24 regulatory requirements and reliability needs for
25 customers in California.

1 We have a smaller set of private storage
2 facilities, we only have two right now, Lodi and
3 Wild Goose, and they come up to 41 bcf total for
4 the private storage out of a 256 total for all
5 instate storage in California.

6 Those two facilities are driven by
7 different forces; it's primarily market forces.
8 They are built physically to allow more cycling of
9 gas in and out of the storage facility on a more
10 frequent basis. And the customers can nominate
11 their gas into and out of the storage facility
12 much more frequently than you can in the utility-
13 owned facilities.

14 So, they are more market driven by daily
15 and monthly prices than reliability needs. They
16 also serve a reliability need, but they can be
17 driven, and their use can be driven by market
18 forces.

19 It's interesting to note how we might
20 get more storage. We did raise this in the 2003
21 IEPR; we identified the desirability to have more
22 storage in California. And I'll note that I think
23 last week or the week before the Lodi storage
24 facility owner just announced that they intend to
25 hold an open season for an additional --

1 exploration for an additional facility closer to
2 the Bay Area. They're interested in pursuing
3 development of additional storage in that area.

4 So I think the Commission's 2003 IEPR,
5 from my perspective, had some assistance and
6 support to move that issue forward.

7 In the market area, again, do higher
8 natural gas prices significantly impact the
9 industrial sector or the entire economy. You've
10 heard from Herb Emmrich that there is a joint
11 study going on by the utilities, with an advisor
12 group from the agencies, to examine that
13 particular question. And hopefully we'll have an
14 answer to that in the fall timeframe. We're not
15 quite sure what the end date is for this, just
16 being explored right now.

17 And then finally, anything extra that
18 California can do to really drive our wholesale
19 prices below the national benchmark. In theory,
20 the prices in California should always be higher
21 than Henry Hub because of the transportation costs
22 that come here.

23 But in reality we've seen, over the last
24 two years at least, that California prices have
25 remained below the Henry Hub, anywhere from 25

1 cents to as much as \$1. In fact, it was about
2 \$1.50 last week because of the differences in
3 demand between the two areas.

4 So, California has benefitted
5 tremendously the last two years. Is there
6 anything that we can do to really keep that
7 situation going to the benefit of Californians.

8 And finally, the last category is
9 stepping back and looking at the entire gas
10 sector, and then also looking at the entire
11 electric sector, as the two systems interface
12 against each other. That is electric sector
13 versus gas sector.

14 There's some over-arching issues we'd
15 like to explore more. And I've listed a few of
16 them here. They really get down to how one system
17 interacts with the other system. That is, are the
18 normal communication protocols adequate for
19 California. This gets down to what we call the
20 gas day.

21 Nomination of cycles on the gas side
22 versus nomination of cycles on the electric side.
23 And they don't match up timewise. It's less of a
24 problem here in California because of the time
25 difference, but there are some -- these things

1 just don't quite match up very well as far as
2 timing.

3 We have a little more concern regarding
4 the coordination protocols between the gas
5 operators -- system operators and the electric
6 system operators during what I call extreme stress
7 periods, where there's an extreme heat storm or it
8 could be a very very cold day, when you have
9 extreme stress on one of the systems, and you have
10 extreme peak demands, either electric or gas. One
11 affects the other tremendously.

12 And this is a situation we saw back in
13 New England a year and a half ago in January of
14 '04 where they came within hours of a complete
15 meltdown of that northeast system because they
16 were using different terms, the gas operators
17 communicating with the electric operators, and
18 there's been a number of investigations on that
19 issue and lessons learned that we've gotten out of
20 those two areas.

21 We need to apply those lessons learned
22 to California and investigate whether we are
23 currently communicating well enough with each
24 other, or whether we need to make any adjustments
25 of those communication protocols.

1 Third issue is there's a lot of movement
2 on the electric supply contract issue down at the
3 CPUC. There's a lot of discussion on the details
4 on the electric side, but one thing that has been
5 left out has been the need to have firm gas supply
6 if you sign a firm electric supply contract.

7 And we're quite concerned that if
8 there's an electric supply contract going forward,
9 that there might not be the fuel to make sure that
10 the electricity can actually be produced.

11 PRESIDING MEMBER GEESMAN: And in that
12 situation what would happen?

13 MR. MAUL: Either prices that the
14 operator has to pay would skyrocket, because they
15 have to go out and purchase gas on a spot basis
16 during extreme peak times when the market prices
17 are very high. Or in the extreme case they would
18 not be able to get gas flowing to their power
19 plant. It wouldn't be able to operate.

20 PRESIDING MEMBER GEESMAN: And would the
21 generator in that circumstance be liable for
22 liquidated damages?

23 MR. MAUL: They might financially be
24 liable, but the question is from a reliability
25 perspective, have to worry about physical

1 delivery.

2 PRESIDING MEMBER GEESMAN: And is there
3 any indication that that's been a problem thus
4 far?

5 MR. MAUL: It hasn't been investigated
6 enough. We've talked to our colleagues, both
7 inside the building as well as the PUC, and we're
8 trying to figure out whether that is a problem or
9 not. And many of us think that it is a problem.
10 We just don't have the facts to lay out a
11 recommendation for you today.

12 PRESIDING MEMBER GEESMAN: Do any of the
13 parties to the contracts, i.e., the utilities or
14 the generators, think that it's a problem?

15 MR. MAUL: We haven't explored that yet
16 with them.

17 PRESIDING MEMBER GEESMAN: I'd suggest
18 when you're dealing with contracts that you ought
19 to talk probably first to the contracting parties.
20 And then always be suspicious that what you're
21 being told by a contracting party is somebody
22 trying to get a little bit better set of
23 circumstances than the written contract provides.

24 MR. MAUL: Okay.

25 PRESIDING MEMBER GEESMAN: But I'd talk

1 to government second, frankly, in evaluating the
2 nature of contractual problems.

3 MR. MAUL: Okay, good advice. Let's
4 see, our last item there is are there any physical
5 limits to shifting energy supply. We obviously,
6 in the southwest for example, have a lot of
7 flexibility in shifting where electricity is
8 generated between Arizona, southern Nevada and
9 southern California to meet, say, an electric
10 demand in L.A.

11 If the electric demand remains constant,
12 for purpose of this discussion, and you have
13 choices in shifting where that electric supply
14 comes from, from an economic perspective or system
15 operator perspective, you make a choice to shift
16 generation from one region to the other region,
17 you now have a significant impact upon gas supply
18 and flows in the gas pipelines. And there are
19 limits to how far we can do that, particularly as
20 we get to stressful situations.

21 And so we're just exploring what the
22 limits of the regional shifting capability are so
23 that system operators, either on the gas or the
24 electric side, know how far they can go if there's
25 a transmission line, for example, shuts down or a

1 gas pipeline shuts down, and they have an
2 emergency call. They need to know how far they
3 can go before they can overload the system even
4 further.

5 PRESIDING MEMBER GEESMAN: I'm having a
6 hard time figuring this one out. I mean is it
7 just another variation on the third bullet?

8 MR. MAUL: Oh, no. No. This is
9 physical limitations of transmission lines versus
10 pipelines. And if you want to generate say 10,000
11 megawatts of power and your choice is I do it in
12 L.A. versus I do it in the southwest --

13 PRESIDING MEMBER GEESMAN: And is this a
14 question of I do it tomorrow, or I do it for the
15 next ten years?

16 MR. MAUL: Oh, no, I do it tomorrow or
17 next week.

18 PRESIDING MEMBER GEESMAN: Okay.

19 MR. MAUL: It's a very rapid response.

20 PRESIDING MEMBER GEESMAN: And your
21 concern is the guy that you're shifting to does
22 not have an adequate supply of natural gas?

23 MR. MAUL: No. The issue there is the
24 system operators, gas system operator and electric
25 system operator, as far as we can tell, haven't

1 talked enough to each other to know the others'
2 limitations. And so the electric system operator
3 may simply assume I can shut down power plants in
4 one area and fire up in a different area, not
5 being fully aware that there may be a gas supply
6 limitation for the other area.

7 So this is a technical issue, trying to
8 figure out physical limitations and how far and
9 how fast you can shift load going back and forth.

10 PRESIDING MEMBER GEESMAN: Because you
11 don't think the generator in the other area has an
12 adequate supply of natural gas?

13 MR. MAUL: No, not -- well, because he
14 might not be able to gain supply through pipe.
15 It's not a contractual issue at all. It's a
16 matter of how much gas supply do you have flowing
17 to certain areas that will support generation.

18 PRESIDING MEMBER GEESMAN: Okay.

19 MR. MAUL: And finally our last two
20 issues gets to the volatility in gas demand caused
21 by the greater use of gas in power plants and the
22 increase in number of power plants in the
23 southwest, both California and Arizona and Nevada.

24 We're seeing some issues on what we call
25 line pack, that is the pressure in pipelines,

1 dropping unexpectedly in the course of a day as
2 power plants all of a sudden come on so fast,
3 because our power plant grid system was built for
4 a relatively level and slowly increasing or
5 decreasing demand. From day to day, season to
6 season it was fairly predictable. And now we're
7 placing a huge demand upon it that wasn't there
8 before, which is the power plant demand, which can
9 very quickly come online or drop offline.

10 And the gas systems were not originally
11 designed to do that. The gas system operators are
12 working quickly to try to readjust their system.
13 But the question is will it cause additional
14 problems.

15 We don't think that it's going to cause
16 a problem for California, but we are seeing some
17 evidence of problems in the Arizona area in
18 pressure drops that are getting down to levels
19 that we're uncomfortable with, that then affects
20 reliability of supply coming to California. So we
21 need to explore that issue more.

22 PRESIDING MEMBER GEESMAN: And is that
23 pressure drops on the interstate pipeline?

24 MR. MAUL: Yes, it is. And finally,
25 again, this is the gas quality issue. The last

1 bullet was will the interchangeability rules, both
2 what we're doing in California in gas quality, as
3 well as what is being done at a national level
4 through FERC and the Natural Gas Council, plus
5 group affect power plant operations.

6 If there is a change in allowable gas
7 quality, will the power plants be able to absorb
8 any changes in what they have historically seen as
9 far as their supply coming to their plant gate, to
10 the turbines.

11 Given the evidence we've just been
12 getting the last month on an extreme -- or on a
13 hot slug of gas coming through Canada into
14 California in early June, we believe that the
15 modern power plants that we currently have in
16 California are actually a little more resilient
17 than what we had originally assumed.

18 So this might not be as big a problem as
19 we had thought, but we are trying to gather all
20 the facts and understand that issue. Because we
21 obviously don't want to change gas quality and
22 then all of a sudden find that you have a very
23 adverse effect on power plant operations.

24 PRESIDING MEMBER GEESMAN: Yeah, my
25 impression from the workshop we held earlier this

1 year was that that was an overstated concern.

2 MR. MAUL: Yes, I agree with you. I'm
3 just teeing this up to make sure we can answer it
4 in the negative.

5 PRESIDING MEMBER GEESMAN: Okay.

6 MR. MAUL: That concludes the issues
7 we've raised in the report. We invite a lot of
8 discussion and comment on these various issues to
9 see if either we can take them off the table or
10 that we can resolve them. Whether we identify
11 them for either short-term or longer term
12 resolution.

13 I think there's a couple different
14 parties that were interested in making some
15 presentations, as well.

16 PRESIDING MEMBER GEESMAN: Great. Why
17 don't we go to those.

18 MR. MAUL: I think the next presentation
19 is -- let's see here. We have one from Bob
20 Howard, I believe.

21 MR. HOWARD: Do you want me to come over
22 there? I mean where would --

23 MR. MAUL: It's your choice. The podium
24 and I'll run your slides for you, or here, either
25 way.

1 MR. HOWARD: Good afternoon. Happy to
2 meet you; I haven't met you yet, Commissioner
3 Geesman. It's a pleasure to be here today. I
4 have talked to Commissioner Boyd. Mike, I haven't
5 met you before; I look forward to having a chance
6 to talk to you.

7 I guess our purpose today is to provide
8 some comments, and when I talked to Dave about
9 coming and my interest in coming, one of the main
10 key messages that I wanted to discuss was the fact
11 that I see a very large disconnect between market
12 prices and production, cost economics.

13 And as I look at the prices that we have
14 seen today, you know, I think frankly, PG&E, at
15 least if we run the same models we're not seeing
16 the same level of prices that are being produced
17 in the models. Mostly because we're letting the
18 prices adjust. And I'll talk about that.

19 But I think what this does reflect, if
20 you look at production costs, and what it costs to
21 bring supplies out of the ground today and what
22 people are producing, and what you see in the
23 marketplace, there's about a \$2 or \$3 difference
24 in the market price that you are observing today
25 and the production cost.

1 Which I believe, if we're trying to ask
2 ourselves questions, is what's the value of
3 bringing an LNG terminal or something like that.
4 It's very hard to measure what those benefits are
5 if we're going to do it that way.

6 To give an example, if I run the models
7 and I get a 25-cent benefit of putting four
8 terminals on the California coast, just as a
9 scenario, you know, while that's \$500 million
10 worth of savings to California consumers, I don't
11 believe that number, 25 cents, reflects the fact
12 that today you're not -- I mean that's on a base
13 of \$4 prices rather than \$7 prices of what you're
14 seeing today.

15 I think a key difference between what is
16 being said as we look at the price differences and
17 the adequacy of infrastructure that, Commissioner
18 Geesman, you were asking about, I'm going to make
19 an edit to my first bullet. The growth in gas
20 supply -- it's really growth in access to new
21 supplies -- is critical for achieving reasonable
22 prices.

23 Right now, sure, we have adequate pipe
24 in the ground to move a demand for the State of
25 California of 6 bcf. But at this particular point

1 we're competing with the rest of the nation for
2 those same supplies. And prices in the rest of
3 the nation are higher, and they're putting
4 pressure on the same supplies that we're trying to
5 access. And so I do think demand in other parts
6 of the country are a significant part of why you
7 continue to see prices to go up.

8 From my perspective what's important is
9 the fact that I don't think customers are all that
10 happy about paying \$7 gas prices. And I think we
11 can do something about it.

12 And it is for us, as a utility in the
13 State of California, even though we're procuring
14 those gas supplies on their behalf, that that is
15 one of the single most concerns that they have
16 when looking at energy.

17 And when you look at it with respect to
18 the electric portfolio, I think that's also a
19 single most concern, because the one area of
20 incremental sources that we are counting on in
21 this state, as well as the rest of the country, is
22 natural gas.

23 We're also counting on natural gas for
24 clean fuels. We're counting on natural gas for
25 hydrogen. We're counting on natural gas for a lot

1 of things, that at \$7 I wonder how long we can
2 sustain these prices and not have a significant
3 detrimental effect on our economy.

4 Gas demand is growing in the Pacific
5 Northwest and the desert southwest much faster
6 than it's growing in California. And that growth,
7 no matter how big or small it is, is being driven
8 primarily by electric generation. And it is
9 necessary to have reliable supplies to continue
10 that growth.

11 And while we support, and we do support
12 aggressive renewable efforts at the margin, I
13 believe that demand is growing faster than those
14 renewable resources that are going to replace
15 them.

16 Let me give a picture. I showed this
17 last time I was here at the LNG conference. The
18 reason why I don't think prices are going to go
19 down in the near term is because demand is growing
20 everywhere but us, and the supplies that are
21 coming online or that are available to us have to
22 move through these demand regions to get to us.

23 You know, whether that's from Texas
24 through New Mexico and Arizona into California;
25 whether it's LNG supplies that are coming into the

1 Gulf. Those supplies are going to be consumed in
2 those regions.

3 PRESIDING MEMBER GEESMAN: So when you
4 say you don't believe prices are going to go down
5 in the near term, does that mean that you disagree
6 with the staff's projection that over the next
7 couple of years prices are going to go down?

8 MR. HOWARD: I don't see it going down.
9 That's right, we do disagree with that.

10 PRESIDING MEMBER GEESMAN: Okay.

11 MR. HOWARD: And I think this is part of
12 the reason why is because there are demand forces
13 in the rest of the country that are driving that.
14 I'll talk about it a little bit more, as well, in
15 another slide that's coming up.

16 You know, we are in a very tight demand
17 and supply balance for natural gas. While there
18 are sources that we can access -- and Herb
19 referred to that earlier today, was the fact that
20 what is limiting us is we don't have access to
21 those supplies.

22 We really haven't found a way to break
23 through that anytime soon. You know, it may have
24 a moment of awakening, but we're not seeing that.
25 And we are seeing the majors move to other parts

1 of the world to develop gas supplies which are
2 much easier to access.

3 Our most promising supplies, you know,
4 that represent the kind of supplies that are going
5 to support an incremental bcf of supply committed
6 to a particular market are from Alaska or from
7 LNG.

8 PRESIDING MEMBER GEESMAN: So you don't
9 place much hope or benefit on the impact on the
10 national market from deliveries from the MacKenzie
11 Delta?

12 MR. HOWARD: They're still years away.
13 And what I'm worried about is what's happening in
14 the next five years.

15 PRESIDING MEMBER GEESMAN: Okay.

16 MR. HOWARD: I mean I believe that
17 supplies from Alaska will arrive. I'm not sure
18 that I believe that those supplies will get here
19 by 2013. I don't think that's very realistic in
20 terms of the scope of that project.

21 And I don't believe that we're going to
22 see the MacKenzie supplies, you know, within the
23 next four years. We're not at all yet in the
24 stage of procuring equipment, materials in order
25 to construct that particular project.

1 PRESIDING MEMBER GEESMAN: And do you
2 think that's likely to have supplies available
3 before the Alaskan project?

4 MR. HOWARD: I think it is likely to
5 have supplies before the Alaskan project. But, I
6 believe the conventional wisdom that that is going
7 to be consumed in Canada.

8 PRESIDING MEMBER GEESMAN: Any impact on
9 the price of natural gas in the lower 48?

10 MR. HOWARD: I don't think it'll have
11 any impact on the price of natural gas in the
12 lower 48.

13 PRESIDING MEMBER GEESMAN: Thank you.

14 MR. HOWARD: I think we'll see the
15 continuation of declines in imports from Canada,
16 at least for the next five years. Mostly because
17 there's a tremendous amount of gas that is being
18 consumed in not just the steam reformation that's
19 occurring to extract heavy tar sands from the
20 northeastern corner of Alberta, but there's also a
21 tremendous amount of natural gas that is being
22 consumed in the production of hydrogen to create
23 the oil, the synthetic fuel, that is being there.

24 So there's a tremendous demand, and with
25 the value of that oil, natural gas is not going to

1 come to the United States at this point.

2 PRESIDING MEMBER GEESMAN: And would you
3 expect that trend to continue for some period of
4 time?

5 MR. HOWARD: Yes. I think we have been
6 able to moderate prices, but I think our prices
7 are getting pulled up with the rest of the
8 country, as you have the tight supply/demand
9 balance.

10 I'm showing you this because, you know,
11 what is an interesting take-away from this
12 particular chart is that if you look at California
13 prices, we are tracking Henry Hub. And we are not
14 the highest prices in the country.

15 I've just picked one, New England, is
16 there, which as our prices have gone up, their
17 prices have gone up. And the volatility has been
18 incredible.

19 What does that tell me? It tells me
20 that I'm competing with New England for those
21 supplies, whether those are coming from the Rocky
22 Mountains or whether they're going to come from
23 LNG. They're having as much trouble siting LNG
24 facilities, although they did succeed in siting
25 one facility in addition to the (inaudible)

1 district gas facility that's there. But that is
2 putting tremendous pressure on the supplies that
3 are in the North American market to get some
4 moderation in those prices.

5 Why are we different than New England?
6 Our belief is because we have infrastructure. Our
7 storage infrastructure does provide us the
8 capability to manage the swings between season in
9 those prices. And frankly, at least in PG&E's
10 market, not necessarily throughout all of
11 California, we have, in PG&E's market at PG&E's
12 citygate, as much liquidity as Henry Hub.

13 In fact, there are times during the year
14 where there are more trades in PG&E's citygate
15 than there are at Henry Hub. It wasn't but three
16 weeks ago that there were 800 trades that were
17 recorded at PG&E's citygate relative to Henry Hub
18 at 600 trades.

19 So I think that is what helps us. And
20 this gets me to a point that I want to make, you
21 know, relative to some of the discussion earlier.

22 Number one, we have, in northern
23 California, a very active third-party storage
24 market. And I'm just getting these statistics
25 because I -- but I traded -- basically over half

1 of the volumes that are trading on PG&E's storage
2 volumes are third-party storage volumes. And
3 they're market-center volumes that, you know,
4 provide a tremendous amount of liquidity, you
5 know, in our marketplace.

6 I don't have the total volumes available
7 that I want to quote, because I don't understand
8 what was given to me here, but I will get that for
9 you.

10 But as you think about that, you know,
11 we're not seeing -- just having that
12 infrastructure is not enough. I mean, as the
13 pressure is being put on the supply basins and the
14 demand is increasing across the country, our
15 prices are going to continue to track up unless
16 there are new supplies, outside of those existing
17 supplies that we access today, that are going to
18 give us a competitive, another competitive point
19 that would actually provide some relief on prices.

20 So where I come from is that we need
21 another new supply. And that is where I differ
22 with respect to the comment that says we have
23 adequate infrastructure. We have adequate
24 infrastructure to continue to deliver the supplies
25 that we get today from the existing supply basins.

1 But we don't have any infrastructure that allows
2 all of us utilities to equally access new supplies
3 that might have some impact upon the price. We
4 need to be able to interconnect with LNG
5 facilities. And I also believe that we need to
6 access LNG facilities directly in California in
7 order to have some effect upon the price.

8 PRESIDING MEMBER GEESMAN: And you think
9 that would be a beneficial impact on customer
10 prices?

11 MR. HOWARD: I think it would have a --
12 I mean the way that I measure it is really in this
13 particular point here. I mean today we can look -
14 - and SERA in the 2000 report last year basically
15 corroborated this, that the marginal production
16 cost of U.S. supplies is somewhere around \$4. Our
17 market price during this last year basically every
18 day of the year was somewhere between \$5.80 and
19 \$8. You know, that's a \$2.80 to \$4 difference
20 from what the production costs are to bring those
21 supplies to market.

22 So I think that somewhere in the range
23 of \$1 is the potential benefit of having
24 additional supplies introduced into the market
25 that could be distributed through the distribution

1 systems that exist in California, with the
2 capacity that we have today if we have the
3 interconnections with those facilities.

4 And so it is that gap between market
5 prices and production costs that are making it
6 difficult to forecast that benefit. And that's
7 where, I think, we've got to spend some time to
8 recognize that we're going to be able to
9 demonstrate that that effect, you know, will
10 occur.

11 I don't think people will believe it
12 until we can kind of show them what we think is
13 going to happen; and somehow we're held
14 accountable for delivering on that. But, at the
15 same time, I do believe, from what we're seeing
16 and what we know about production, economics in
17 the North American supply basins, that there is
18 that disconnect. And we can point to that
19 disconnect.

20 I think, and really this kind of gets me
21 to my concluding points, is that, you know,
22 natural gas is vital to our economy. And one of
23 the ways that we are working together with the
24 other utilities in the state, and we're working
25 with Dave and his people, is to look at, you know,

1 what's going to happen if we really do see a
2 sustained level of prices at this level to the
3 California economy over the next three to five
4 years.

5 And so we're working actually to
6 measure, you know, those impacts in terms of what
7 the impacts could be on demand disruption and what
8 risk that creates to the economic engine that is
9 providing the growth to our state and that are
10 providing the incomes that support all of us.

11 I also see us counting on natural gas
12 with respect to improving air quality in the
13 state. You know, at this particular point, clean
14 air transportation is being driven by the use of
15 CNG or LNG or hydrogen. All of which are derived
16 from methane gas in some form; 95 percent of the
17 country's hydrogen is produced from natural gas.

18 So if we're counting on that resource
19 we're going to need that resource. So developing
20 that new supply in an economic fashion is really
21 critical to where we need to go, I believe.

22 So, it is -- I am saying that new
23 infrastructure is needed. We need to be able to
24 connect to those supplies to be able to capture
25 the volumes that would enter California for all

1 the consumers in California.

2 And I believe that will need, and I
3 agree with the CEC and the reports and the
4 discussions today so far, we will need more
5 storage. We bring in a new supply at an increment
6 of 500 a day, not all of that is necessarily going
7 to get consumed in that day. But we can store
8 that gas, and that would be good for our economy.
9 And it has benefitted us in the past.

10 So, it is a case of a need for
11 infrastructure. It's a different kind of
12 infrastructure. And with a little more time, or
13 in your questions, I do have a different concept
14 of slack capacity. Because at the end of the day
15 what I provide as a business is pressure. The
16 compressors that take that gas from the state to
17 the ends of our distribution system and the
18 inventory that we have in the pipeline is what is
19 necessary to provide the gas to the burner tips
20 across the state.

21 And so it's really not slack capacity,
22 although I can, and I do, as a transporter,
23 provide people access to transmission capacity so
24 that they can access their own supplies. And it
25 does work extremely well, but it's not slack. And

1 at the end of the day I need that capacity to
2 deliver to residential and commercial customers
3 across the state.

4 I really do appreciate the opportunity
5 to be here and I'd love to answer any questions
6 that you have.

7 PRESIDING MEMBER GEESMAN: I understand
8 your discussion of the need for new infrastructure
9 to be principally focused on new LNG-related
10 infrastructure, as opposed to additional
11 interstate pipeline infrastructure?

12 MR. HOWARD: That's right. I mean I
13 believe that at some point we will need it, for
14 intrastate pipeline infrastructure. But there's
15 got to be a new supply behind it to really make it
16 economic. And I don't see those new supplies
17 coming yet at that point. And it doesn't make
18 sense to invest in that infrastructure unless
19 you've got a new supply that's going to be behind
20 that, that can have some influence on the overall
21 prices in the market.

22 PRESIDING MEMBER GEESMAN: Were you here
23 this morning when the staff discussed the
24 influence in their model of additional LNG coming
25 into the Gulf Coast?

1 MR. HOWARD: Yes -- I wasn't here this
2 morning when that has, but I have had some
3 discussions around that. I take a slightly
4 different view from the perspective that I believe
5 if you looked at my hot spot chart that much of
6 that gas, as demand grows in the south, which is a
7 very, you know, vibrant economy, is going to get
8 consumed in the south.

9 So I don't know how much of that
10 actually makes it. I understand our models, you
11 know, do capture that. But I've got to look at it
12 really on a fundamental basis. And I believe that
13 given the declines that you're seeing,
14 particularly in the shallow gulf, and that you've
15 seen the delays in the development of blue water
16 gulf, or deeper gulf, that, you know, what LNG is
17 doing for us right now is basically fulfilling the
18 declines that are occurring, and is being consumed
19 there.

20 PRESIDING MEMBER GEESMAN: Thank you.

21 MR. HOWARD: You bet.

22 COMMISSIONER BOYD: While you're there
23 I'd like to ask a question. I haven't said it yet
24 today, but I'm saying it now. In many other
25 forums I've expressed my opinion that if and when

1 Alaskan gas comes down to the lower 48, while
2 those molecules aren't coming to California,
3 they're going east to meet the economics, which
4 are demand driven, because the east is converting
5 more and more to gas as California did 20 years
6 ago, for environmental reasons and otherwise.

7 And so although I get arguments that
8 sending that gas east relieves pressure from other
9 sources in the country, in the Rockies and what-
10 have-you, where that gas can come west, I'm pretty
11 skeptical about that.

12 And thus that's led me, more and more
13 over the past two, three years, to look, like you
14 do, perhaps to some degree, look to gas from the
15 west, i.e., LNG.

16 Do you have any different view with
17 regard to where Alaskan gas, if and when it comes
18 down here, is going to go, and whether that's
19 going to be much of a relief to California?

20 I note in your charts you mention --

21 MR. HOWARD: Right.

22 COMMISSIONER BOYD: -- LNG and Alaskan
23 gas will be positive for California. I'm curious
24 as to how positive will Alaskan gas be.

25 MR. HOWARD: I mean I think I probably

1 am closer to your view, Commissioner Boyd, that I
2 think we're going to have to fight to get that
3 gas. You know, one, the economics are just, you
4 know, take it straight down in a bullet line, you
5 know, as far east as you can take it and
6 distribute it to meet those east coast markets.

7 And, you know, in my own personal
8 experience, you know, as I've looked to make sure
9 that we're in a position of accessing that gas,
10 it's usually a little bit of a fight to, you know,
11 say that we're going to get that, because they
12 don't see the size of our market as really being
13 sufficient to attract the capital investment to
14 get that gas.

15 So, that's been the personal experience
16 that I've had is that there's just not enough
17 there for us to get some of that, unless there's a
18 fundamentally different change in the dynamic of
19 that, of the volumes and what the investment is
20 going to be.

21 I think that for me the question is to
22 basically make sure that we have, you know, a very
23 adequate, you know, train of those new supplies,
24 because again, you know, it is getting more and
25 more expensive to produce the resources that we

1 are close to.

2 I mean the Permian Basin is in decline.

3 It does reflect the reason why we do have lower
4 volumes on El Paso's line that was referenced
5 earlier. And in the Canadian basin more of that
6 gas is being consumed in Canada, so our imports
7 have been declining 4 percent a year since the
8 year 2000 from Canada. And that's why you're
9 seeing much lower volumes, or much lower
10 utilization level on GTN.

11 We have filled that gap with Rocky
12 Mountain gas, but really where's Rocky Mountain
13 gas going to go in the next few years is that
14 there's, you know, I mean if you look at the
15 project 1903, Rocky Mountain gas right now is
16 going to go, or incremental supplies of Rocky
17 Mountain gas are going to go to Arizona. The way
18 the people that are on that particular project.
19 So we're not keeping that gas here to be consumed,
20 to have a beneficial effect.

21 So it does, you know, support the point
22 that I have, is that there's demand in a lot more
23 other areas that are growing faster than
24 ourselves, that are taking that gas away based
25 upon the existing supply curves that are serving

1 our markets, that they can access more premium
2 markets and get more value for the gas that
3 they're selling.

4 So, unless we can find other supplies,
5 you know, to bring that here, we're not going to
6 turn that dynamic around; unless another thing is,
7 is we're willing to commit to some of those
8 supplies. And to keep them here.

9 COMMISSIONER BOYD: Thank you.

10 MR. SMITH: Mr. Howard, a quick question
11 for you on storage. Do you have a sense, or do
12 you know how much storage should be added to
13 PG&E's system in order to affect that price
14 moderation, the benefit that it provides, as well
15 as filling the gap between average annual demand
16 and peak demand in California?

17 MR. HOWARD: You know, I mean I have to
18 admit, I mean I think the world of storage and I'm
19 very proud of the fact that PG&E is one of the
20 biggest storage providers in the country. We're
21 not, certainly, as large as SoCalGas; they're
22 bigger than us, but it's a great resource that we
23 have in California and it saves us a lot of money
24 in ways that we don't have to hold as much
25 pipeline capacity.

1 But, you know, storage, in and of
2 itself, is, you know, like a battery. I mean you
3 put it in for a price and you get it out for a
4 price. But you're not really -- I mean you are
5 affecting the liquidity. But at the end of the
6 day, when it comes to the long-term price, storage
7 is not really going to be the supply. It's
8 capacity.

9 And it's a substitute for pipeline
10 capacity. And if you're not accessing more supply
11 or an incremental supply, that is not going to
12 affect the long-run dynamic associated with the
13 price of natural gas in the state.

14 So, I mean I'm not intending not to
15 answer your question, I think we need storage
16 resources. To the extent that you've got, you
17 know, a new supply that's coming in that is, you
18 know, maybe more than you need at a particular
19 point in time, you know, I think there is room to
20 expand storage and we ought to be doing that.

21 But, you know, relative to your question
22 of really the effect on the price of natural gas,
23 I think it's not really the long term end to
24 getting to that point. We need the supplies to
25 back it up.

1 MR. SMITH: And that's understood.

2 MR. HOWARD: Okay.

3 MR. SMITH: I guess perhaps my question
4 deals more with PG&E recognizes that storage is
5 needed, along with --

6 MR. HOWARD: Right.

7 MR. SMITH: -- additional pipeline
8 capacity. Do you -- for PG&E's system is the need
9 for storage for the benefits that it brings, --

10 MR. HOWARD: Right.

11 MR. SMITH: -- is the need for storage
12 immediate? Are you envisioning adding storage on
13 the longer term. Or can you give us a sense of
14 PG&E's plans for adding storage?

15 MR. HOWARD: Good. We don't have any
16 plans to actually expand storage capacity. We
17 have the ability to. Really, the way I look at
18 the need for storage is, in part, driven by our
19 seasonal demand for natural gas.

20 In the wintertime for our total system
21 requirements as much as 30 percent of the natural
22 gas delivered is coming out of our storage
23 facilities. I cannot deliver and meet the peak
24 demand without having storage.

25 And that has been to the benefit,

1 because I don't have to have the full pipeline
2 capacity that's required to do that. But it puts
3 storage as, really, the linchpin of our
4 reliability.

5 With respect to market storage or the
6 others that desire to use storage or take
7 advantage of the seasonal swings in price and the
8 liquidity that's created by that, I mean we've got
9 a very vibrant market. You know, we think we
10 fulfill that market every day. We think that if
11 there was more capacity we could fill it. And we
12 think if we added LNG as a supply to the State of
13 California, you know, we'd love to be one of the
14 participants in that market, competing with the
15 other private storage providers, to be able to
16 serve that market and provide that service. And
17 expand to meet that need.

18 You know, at this point that demand's
19 not necessarily here. It's based upon the
20 existing supply, so as that develops, I mean,
21 we'll look forward to trying to grow to meet those
22 requirements in the state. But I don't have a
23 number at this time.

24 PRESIDING MEMBER GEESMAN: Thanks very
25 much.

1 MR. HOWARD: Thank you very much.

2 PRESIDING MEMBER GEESMAN: I had a green
3 card from Kan Ley, MRW Associates.

4 MR. GOPAL: She said the question has
5 been answered.

6 PRESIDING MEMBER GEESMAN: Oh, okay.
7 (Parties speaking simultaneously.)

8 PRESIDING MEMBER GEESMAN: Excellent.
9 Next up.

10 MR. MAUL: Next up we have Jeff Hartman
11 from SoCalGas, if I can find his --

12 MR. GOPAL: Look on the bottom.

13 MR. MAUL: The bottom?

14 MR. GOPAL: Bottom.

15 MR. MAUL: Let's see here -- Jeff, there
16 we go; find it here.

17 MR. HARTMAN: Thanks. Hi, I'm Jeff
18 Hartman representing Southern California Gas
19 Company and San Diego Gas and Electric. And we
20 appreciate the opportunity to provide our thoughts
21 and input on the issue of gas policy issues as
22 they affect the infrastructure.

23 Our basic vision for the natural gas
24 reformation is that the state really should
25 implement a comprehensive gas framework in

1 southern California to help customers reduce their
2 energy costs. You've heard previous speakers talk
3 about the benefit of increased access. And I've
4 got a slide to sort of highlight that.

5 Specifically we have some proposals
6 before the PUC at this time that are designed to
7 accomplish three objectives. First, to increase
8 customer choice, encourage the development of new
9 supply sources, and then insure that there's
10 infrastructure adequacy to meet their needs. So
11 that the infrastructure follows exactly what the
12 customers are desiring.

13 This is a chart we've used many times
14 before. Cambridge Energy Resources prepared this
15 assessment for us several, I'm going to say about
16 a year and a half ago. And what we tried to do
17 was look at what would happen if you added
18 additional LNG terminals on the west coast.

19 And so they ran some scenarios adding
20 with the basecase of no west coast terminal versus
21 one terminal, two terminals and three terminals.
22 And to the point where with three terminals you're
23 adding an additional 2 bcf a day of new supply
24 access into the west coast.

25 And as you can see, you're potentially

1 reducing the California gas, the border price by
2 about \$2 per million Btu from that new supply
3 source. So when you look at it for customers in
4 the southern California area, that potentially
5 amounts to a savings of \$300 million to a billion
6 dollars annually in just their commodity
7 procurement costs.

8 There's been a lot of discussion about
9 the adequacy of the gas infrastructure. And I'm
10 going to also repeat that the southern California
11 gas infrastructure is adequate to meet our
12 customer requirements.

13 We have almost 3.9 bcf a day of backbone
14 receipt capacity that provides access to multiple
15 sources of supply in the western United States.
16 We have the largest storage capacity in the State
17 of California, approximately about half of the
18 state's total, 122 bcf of inventory.

19 We've got significant withdrawal and
20 injection capacity. And I've listed the ranges
21 here. Obviously the upper end of the range for
22 withdrawal reflects the fact that our storage
23 fields are full. And the upper end of the
24 injection capacity reflects that fact that our
25 storage fields are empty. But that gives you an

1 idea of the type of deliverability capability of
2 our system.

3 However, to understand infrastructure
4 adequacy, you have to understand what the purpose
5 of that infrastructure is designed to do. And
6 when I talk about almost 3.9 bcf a day of backbone
7 receipt capacity, that's basically the capacity
8 that's designed to redeliver supply from an
9 interstate source or PG&E or California
10 production. And then put it into the distribution
11 system for redelivery to the end use customer.

12 The storage capacity, again, also is an
13 integral part of that, and let me now talk about
14 how it's integrated when you integrate those
15 capacities in with the distribution system.

16 For example, on the SoCalGas system, on
17 a peak day we can theoretically 6 bcf of gas to
18 end users. We haven't ever had to do that. Our
19 highest peak was 5.3 bcf in December of 1990.

20 On the San Diego system they have
21 capacities that range from 655 to 635 depending on
22 seasonal time. And their actual most recent peak
23 throughput was about 659.

24 The key thing I want to emphasize,
25 though, is when you look at the backbone and

1 receipt system with the upstream suppliers that is
2 not the type of infrastructure that is designed to
3 meet peak day needs. Sure, it can on certain
4 days. But it's really designed to provide average
5 annual usage. And then integrated with the
6 storage and distribution system provides the peak
7 day coverage.

8 So when I say the backbone system is
9 adequate, what I'm saying is we're basically
10 delivering a lot less supply into that system than
11 is needed on an average annual basis.

12 And you can also see on a peak day
13 system on the SoCal system there's also quite a
14 bit of capacity, excess capacity to meet peak day
15 needs.

16 I've shown you graphically here what it
17 looks like on the SoCalGas system. And the data
18 is actual daily data through May 30th of this
19 year. And as you can see, even though there's
20 been some daily fluctuations in usage of the
21 backbone system, there was still quite a bit of
22 excess, except for during the 2000/2001 period.
23 And that's when that led us to initiate some
24 additional expansion of the system from 3.5 bcf a
25 day to 3.875.

1 Going forward, as you can see, the
2 system is still fairly under-utilized.

3 On a forecast basis we end up with that
4 same general pattern. And although the forecast
5 is of demand and not of receipts of the system, we
6 can't forecast when and where suppliers and
7 customers are going to use our backbone system,
8 but we make some general estimates of what overall
9 demand is to give you an idea of what that profile
10 will look like.

11 And just to give you a sense as to what
12 could happen if some unusual events occurred, we
13 overlaid in the light blue the scenario where we
14 ran a one-in-35 cold year, extremely cold year
15 condition, overlaid with a one-in-35 dry hydro
16 condition, so that we not only boosted residential
17 and core heating demand, but gas use for electric
18 generators. And as you can see, it pushes up the
19 average usage. But it still leaves a fair amount
20 of unutilized capacity on the backbone system.

21 This is a similar chart for SDG&E. And
22 although SDG&E's system is more of a local
23 transmission system, in comparison, because it's
24 really taking supply from the SoCal system and
25 redelivering it to end users, I've put this here

1 to show you for two reasons.

2 First, as demand declines on the SDG&E
3 system it actually creates greater reserve margin.
4 But, second, to the extent that there is new LNG
5 supplies coming into the southern end of SDG&E's
6 system at Otay Mesa, what you're going to see on
7 the SDG&E system is also similar to a backbone
8 receipt system. So, that's why it's relevant on a
9 going-forward basis.

10 Now, let me talk a little bit about the
11 policy proposals that we put forth before the PUC.
12 There's an ongoing proceeding looking at the
13 expansion policies. And what we have suggested to
14 the PUC is to maintain our existing policy, which
15 is basically that we would expand our backbone
16 receipt capacities to insure that there's a
17 reserve margin of about 20 to 25 percent above
18 expected demand.

19 We believe that's the most cost
20 effective way to meet the expected variations in
21 demand without raising end use transportation
22 rates unreasonably. And it also provide -- we
23 also want to provide customers with access to new
24 supply sources to manage their procurement costs.
25 We've specifically proposed to the Commission that

1 when the benefits of those new supply sources, the
2 access to those supply sources exceed the costs,
3 the expansion cost should be rolled into system
4 rates. Otherwise, if it's not the case, then we
5 would suggest that the shippers who want that
6 capacity should have to pay for that expansion.
7 And then we'd go ahead and institute it.

8 We've stated many times to the PUC that
9 we believe the commodity benefits of additional
10 access actually exceed the cost of the facilities.
11 However, to date the Commission has ruled that we
12 should charge those suppliers on an incremental
13 basis. And so all work to provide access for new
14 LNG sources is going forward on that basis in the
15 interim.

16 Now, for local transmission policies,
17 what we've also said to the Commission that we
18 will expand to meet what we call our expectations
19 of core demand going forward, as well as noncore
20 firm service commitments. And one of the ways we
21 gauge noncore requirements is we basically ask
22 them how much do you want. It's a common practice
23 in the industry; it's called an open season.

24 And this way what we're saying to the
25 customers is tell us how much you really want and

1 then we'll look at that. And if we have enough
2 capacity we'll award it. And if not, you're
3 willing to make a commitment to us, we'll go out
4 and build it.

5 And, again, we think that provides a
6 fair allocation of the existing capacity; and
7 insures that any expansion we make is cost
8 effective. In other words, that the expansion is
9 actually used by customers.

10 Now, with respect to storage. At this
11 time we believe we have sufficient storage to meet
12 all our customer requirements. I can't tell you
13 what's going to happen when and if LNG suppliers
14 come in. There's been speculation that that will
15 increase the demand for storage. You've also
16 heard that storage is a substitute for flowing
17 supply.

18 If that's the case, and you add
19 additional supply you may actually see a drop in
20 the demand for storage. I can't answer that
21 question now. But what I can tell you is the
22 market thinks the demand for storage is going to
23 drop. And I can judge that primarily by the fact
24 that the amount of storage that we have under
25 long-term contract in the unbundled storage market

1 is declining every year.

2 As you know, most of the storage is
3 allocated to the SoCalGas core to provide for
4 reliability in the wintertime. The remainder of
5 the storage, about 47 bcf, is marketed under the
6 unbundled storage program. That means shippers
7 and customers are free to take as much storage as
8 they want.

9 And what they're telling us now is
10 they're not willing to make any commitments over
11 the long term.

12 However, we do want to insure that
13 market participants that truly desire the
14 additional storage services will have that
15 available. And, again, to the extent that we can
16 get commitments for the additional storage
17 services, we'll go ahead and make that investment.
18 And we do have that opportunity, with the existing
19 reservoirs, in our storage fields today.

20 But, again, --

21 PRESIDING MEMBER GEESMAN: How long has
22 that decline in demand for storage services been
23 going on?

24 MR. HARTMAN: The decline for long-term
25 storage has been going on for about the past three

1 years.

2 PRESIDING MEMBER GEESMAN: And what's
3 the rate of decline?

4 MR. HARTMAN: I would say the average
5 term is now dropping to roughly a little over a
6 year in terms of length of storage. Whereas
7 previously we had, it was fairly common for us to
8 have three- to five-year storage contracts.

9 PRESIDING MEMBER GEESMAN: So, are you
10 still storing the same volumes, just under shorter
11 term contracts or --

12 MR. HARTMAN: That's a different issue.

13 PRESIDING MEMBER GEESMAN: Okay.

14 MR. HARTMAN: The amount of gas that's
15 actually stored is a function of how end users use
16 those storage rights. You heard David earlier
17 mention that the core has very specific
18 requirements to meet.

19 So, for example, every November 1 they
20 have to have a certain amount of storage in the
21 ground. And they meet those commitments.
22 However, noncore customers, or unbundled storage
23 customers, are free to use or not use their
24 storage capacity.

25 Last year we had an all-time high in

1 storage. It was almost 122 bcf stored in our
2 fields. Previous years it hasn't been quite that
3 high.

4 So I would say the utilization is
5 usually a function of short-term price
6 differentials.

7 PRESIDING MEMBER GEESMAN: How about,
8 and I don't know how you'd describe it, but volume
9 of storage capacity under contract. Has that been
10 declining or has it simply been shortening up in
11 terms of term of contract?

12 MR. HARTMAN: It's shortening up in
13 term.

14 MS. JONES: And can I clarify, when
15 you're talking about your customers needs or
16 requirements, you're talking about what you're
17 required to do for your core customers, and your
18 assumption is that you have curtailment ability
19 for noncore customers who do not take care of
20 their own needs.

21 MR. HARTMAN: Specifically for storage
22 that's a separate issue, you're talking noncore
23 transportation?

24 MS. JONES: Yeah.

25 MR. HARTMAN: Okay. The core has a

1 certain, obviously there is a curtailment priority
2 queue, --

3 MS. JONES: Um-hum.

4 MR. HARTMAN: -- and actually storage
5 withdrawals, firm storage withdrawals are not
6 curtailed ahead of noncore transportation.

7 So the first thing that would be
8 curtailed would be transportation, not storage
9 withdrawal.

10 MS. JONES: Okay. Thank you.

11 MR. HARTMAN: The other point that we've
12 made in our recent filing to the PUC is that there
13 needs to be a symmetry between the risk reward for
14 storage investments. Right now that requires
15 clarity and if you clarify that, that makes it
16 easier to insure that when the customers desire
17 the storage facilities, that the utility, in this
18 case SoCalGas, can go ahead and construct those
19 facilities.

20 PRESIDING MEMBER GEESMAN: What you mean
21 by that last point is symmetry to the storage
22 user?

23 MR. HARTMAN: No. To the owner of the
24 facility, it would be the utility. Right now the
25 original storage decision in 1993 had an intent to

1 place all the storage at 100 percent utility risk.

2 In the interim the PUC has moved to a
3 50/50 risk/reward ratio sharing mechanism. So you
4 have the potential that the utility could incur
5 100 percent of the cost and only realize 50
6 percent of the revenue. And that provides a
7 disincentive to go ahead and invest -- it's hard
8 for me to go to my shareholders and ask for money
9 under that kind of term.

10 PRESIDING MEMBER GEESMAN: Okay, so what
11 you're then suggesting is that interim approach be
12 amended or altered.

13 MR. HARTMAN: Well, it needs to be
14 clarified so that's symmetrical.

15 PRESIDING MEMBER GEESMAN: Okay.

16 MR. HARTMAN: And that hasn't been an
17 issue because we haven't had a real need to expand
18 storage. Or the recent storage expansions that
19 were done were done under PUC authorization that
20 actually provided a cost mechanism, a cost
21 recovery mechanism for those specific expansions.

22 PRESIDING MEMBER GEESMAN: And that's
23 proven to be satisfactory?

24 MR. HARTMAN: Yes. All right, I want to
25 talk a little bit about the overall framework for

1 gas coming into the southern part of the state.
2 Because we believe it's very important that in
3 order to encourage new sources of supply, we need
4 to make some enhancements to the framework that
5 currently exists in southern California.

6 Some of those changes have already been
7 adopted in northern California, but not in the
8 south. And that's caused an issue for what I'll
9 call supply security uncertainty.

10 There are three things that we've
11 recommended to the PUC that need fixing, and they
12 need it fixed to insure that the suppliers and
13 customers who want to access that new supply can
14 do so with certainty.

15 And the first is to adopt a system of
16 firm access rights, so that customers and
17 suppliers will have that certainty that when they
18 contract for the supply it will be redelivered
19 from that upstream source to the burner tip.

20 At this time all customers who want to
21 bring gas into southern California have what is
22 called interruptible access. The priority of
23 access is determined by the rights they hold on an
24 interstate pipeline.

25 So even though an interstate pipeline

1 may provide firm service to a customer or a
2 shipper, they have no requirement that that match
3 a downstream takeaway. And that has caused a
4 dislocation in providing gas into southern
5 California that you don't have in northern
6 California.

7 PRESIDING MEMBER GEESMAN: My
8 recollection is that we addressed these top two
9 bullets in our 2003 report. I don't think anybody
10 responded to them, but I believe we did address
11 both of them, did we not?

12 MR. HARTMAN: Well, we still are
13 pursuing a system of firm access rights in
14 southern California.

15 COMMISSIONER BOYD: We're all waiting.

16 PRESIDING MEMBER GEESMAN: Yeah, I think
17 as they say on the radio, ditto to that.

18 MR. HARTMAN: And the other piece if
19 providing equal access for all suppliers so that
20 there's gas-on-gas competition. And that will
21 insure that customers in all of southern
22 California are receiving the correct price signals
23 when they schedule their supplies.

24 We filed that proposal again with the
25 Commission in June. It's what's commonly called

1 the system integration proposal. We already have
2 operational integration of the two systems. Now
3 we're proposing that they schedule gas on an
4 integrated basis.

5 And then finally, you heard David talk
6 about how we can provide storage access to
7 customers in Arizona/Nevada area to, in a sense,
8 make the market more fluid, and provide more
9 protection for us.

10 Right now SoCalGas is precluded from
11 redelivering gas from our system to an out-of-
12 state customer. We had asked the PUC on a interim
13 basis to give us that on an interruptible basis,
14 but they did not approve that tariff filing.

15 In the firm rights proceeding that the
16 Commission has underway, their OIR, they have
17 deferred this issue to a time to be determined.
18 And so our position is that to the extent that you
19 can remove those barriers you will provide greater
20 incentives for new supply sources to want to
21 access supply into southern California.

22 Because it's very possible that on some
23 days California can't use all the gas, or southern
24 California can't use all the gas that the LNG
25 suppliers would want to deliver. You saw on that

1 chart potentially 2 bcf a day if you had four
2 terminals.

3 We have some days where our actual
4 receipts from our interstate suppliers and
5 California producers is well below 2 bcf a day.
6 That means the gas has to go somewhere else off
7 our system, or else they're not going to have
8 certainty that they can redeliver their gas. And
9 it's going to inhibit their ability to bring their
10 projects to market.

11 PRESIDING MEMBER GEESMAN: And have you
12 always been precluded from that? Or is that a
13 legacy of the energy crisis?

14 MR. HARTMAN: Well, there's a theory
15 that says we have authority under FERC
16 authorization. But we've specifically asked the
17 PUC for that authorization, as well. And we have
18 not been granted that authority.

19 PRESIDING MEMBER GEESMAN: Thank you.

20 MR. HARTMAN: Thank you.

21 PRESIDING MEMBER GEESMAN: Thanks very
22 much. Blue card from Sean Edgar.

23 MR. EDGAR: Commissioners and Staff,
24 good afternoon. Sean Edgar on behalf of the
25 California Refuse Removal Council. And you may

1 ask what a garbageman is doing up here in front of
2 he Energy Commission today, --

3 PRESIDING MEMBER GEESMAN: They come all
4 the time.

5 MR. EDGAR: Actually Ken Lay just called
6 and he said he was real busy with his lawyers
7 today or he would have been here personally.

8 (Laughter.)

9 MR. EDGAR: Just a few items, if I may.
10 As a brief introduction our California Refuse
11 Removal Council is engaged in, it's a nonprofit
12 trade association comprised of about 100 family-
13 owned companies providing services to about 6
14 million Californians. We do so, operating about
15 4000 heavy duty vehicles. The majority of those
16 are diesel vehicles. Many are separate multiples
17 of hundreds or natural gas vehicles.

18 And my few specific comments pertaining
19 to I captured from Mr. Howard's presentation that
20 PG&E is counting on future natural gas supplies to
21 supply the transportation fuel market.

22 And as we see a lot of our fleet's
23 transition either by the choice of our customer or
24 by a regulatory mandate, or by a decision of a
25 judge somewhere, we're not sure really who's

1 driving, what kind of truck we're going to be
2 driving tomorrow.

3 However, we see the migration toward
4 natural gas occurring. And I saw it mentioned,
5 like I say, in Mr. Howard's presentation. But one
6 of my key questions would be where is that supply
7 coming from. And I don't see those numbers
8 captured in this process.

9 So not that anybody has the answer right
10 now, but I'd appreciate the continuing dialogue.
11 I would like to get a sense if, as an example, the
12 linkage between this process today and your
13 petroleum dependence group, which will lead me
14 into a few comments on supply and a few comments
15 on cost.

16 Your petroleum dependence group had one
17 of the scenarios there that an aggressive
18 penetration of natural gas in the heavy duty
19 transportation structure, or heavy duty
20 transportation network throughout about a million
21 vehicles in California, heavy duty diesels. If we
22 converted all those to natural gas we would
23 realize a cost savings of \$1.77 billion.

24 And the math is a little bit fuzzy for
25 me, but on the supply side I'd really like to

1 understand and have that captured in this process.
2 Our conventional -- and also I'm actually going to
3 move back to southern California and be one of Mr.
4 Hartman's customers, because I heard him say he
5 wanted to see cost come down. And, Mr. Howard, I
6 thought I heard you say that costs are going to
7 stay where they are in the short term.

8 So, I may move back to southern
9 California.

10 COMMISSIONER BOYD: They can't both be
11 right.

12 MR. EDGAR: Well, we'll see. And
13 particularly by the time, with regard to delivery
14 infrastructure. And from our standpoint, you
15 know, we take out of pipeline and via on our CNG
16 systems that we use for vehicle fueling, the
17 cheapest infrastructure we have is about a
18 \$500,000 group of compressors to get compressed
19 natural gas. About \$750,000 to get liquified
20 natural gas, which, by the way, is brought in in a
21 diesel-burning truck from Arizona or Wyoming or
22 somewhere else to supply tanks in small
23 quantities. And when that diesel-burning truck
24 gets slowed down, our garbage trucks,
25 unfortunately, don't go out.

1 And then, of course, we can use a
2 liquefier system, take (inaudible) gas, liquify
3 it. PG&E has a unit here in Sacramento, and
4 that's roughly, I think, for about \$2 million.

5 So the fueling infrastructure for us to
6 get to migrate in large quantities to natural gas
7 as a transportation fuel, I'll be addressing that
8 in the other element which unfortunately I guess
9 we won't have another bite at the apple before the
10 end of this year with regard to the petroleum
11 dependence segment, and specific to the issue I
12 mentioned.

13 But we're looking forward to at least on
14 the supply side we'd like to have that captured in
15 this process about where does that fit within
16 the -- that you mentioned.

17 PRESIDING MEMBER GEESMAN: We will
18 address that, and you will get a couple more bites
19 at the apple. Commissioner Boyd and I are
20 supposed to come up with a draft Committee report
21 in early September that we'll then hold hearings
22 on before submitting it to the full Commission in
23 early November for the Commission's consideration
24 and adoption.

25 And we will tie in the various elements

1 from the now 46 days of hearings that we've held.
2 We spent an extensive amount of time last week on
3 alternative fuels; heard from the Natural Gas
4 Vehicle Trade Association, as we've heard a couple
5 of times before.

6 And also got into this topic, I believe,
7 last December when we were originally discussing
8 gas demand forecasting methodology. And I'm not a
9 good one to be trusted with verbal restatement of
10 numbers, but my recollection is that the
11 aggressive penetration of natural gas into the
12 transportation sector would hypothetically
13 represent about 5 percent of natural gas demand in
14 California, which is a significant amount. And
15 one that I think Commissioner Boyd and I need to
16 ponder, and then address in our Committee report.

17 MR. EDGAR: Good, and I appreciate that,
18 Commissioner. I'll just wrap up saying that the
19 gas quality issue is also important. We will be
20 participating in the (inaudible) thing. We're out
21 there buying what amount to \$50,000 engines,
22 somewhere around there. The quality of gas that
23 goes into keeping those engines on the road is
24 very critical when we're out picking up your
25 garbage and recyclables.

1 So, thank you very much. Thank you for
2 the process. Look forward to seeing you again
3 soon.

4 PRESIDING MEMBER GEESMAN: Thanks for
5 being here.

6 COMMISSIONER BOYD: Do you have any
7 plans for augmenting our methane supply with some
8 of your landfill gas?

9 MR. EDGAR: Actually, yes, sir, we do.
10 We've actually, for our folks that are operating
11 landfill facilities, our members operate about 14
12 of the 176 active landfills here in the state.
13 It's about 10 percent, our membership.

14 But the national companies have really
15 taken a lead toward that. And actually we're
16 looking more aggressively at a variety of the
17 conversion technologies to be able to get biogas,
18 ethanol, other of those items, especially
19 gasification technology.

20 And I'll project with the push of
21 organics that we see -- we serve multiple masters,
22 not only the customer at the curb, but also
23 industrial and some ag. And as we see really a
24 supply push of organic materials in the Central
25 Valley in particular, because of no more burning

1 of ag residuals, we see that carbonaceous waste as
2 a potential to mix with a lot of the greenwaste
3 that we already take, and get it converted into
4 some sort of a fuel or gas product. So we're
5 looking to commercialize that here in the next
6 couple of years.

7 COMMISSIONER BOYD: I really just wanted
8 to offer you the opportunity to give a commercial.

9 (Laughter.)

10 MR. EDGAR: Your trash is our cash,
11 that's the commercial we're --

12 (Laughter.)

13 MR. EDGAR: -- that's the commercial
14 we're trying to get to. So, hopefully we can get
15 there on the conversion technologies.

16 Thank you.

17 COMMISSIONER BOYD: Thank you.

18 PRESIDING MEMBER GEESMAN: Thanks very
19 much.

20 Anybody in the audience care to address
21 us? I don't think we have anybody on the phones,
22 do we? Anybody on the phones care to make a
23 comment?

24 Okay, a long, fruitful day. Thank you
25 very much. We'll be adjourned.

1 (Whereupon, at 4:50 p.m., the hearing
2 was adjourned.)

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